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BEFORE THE

PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Power and Light Company for Authority to Increase Retail Electric, Natural Gas and Ripon Water Rates — 6680-UR-114

FINAL DECISION

This is the final decision concerning the application of Wisconsin Power and Light Company (WP&L or applicant) for authority to increase electric and natural gas rates in 2005.

Final overall rate changes are authorized consisting of an $18,641,000 annual rate increase for Wisconsin retail electric operations (2.22 percent), and a $2,035,000 annual rate increase for natural gas operations (0.78 percent). These rate increases are to be applied to the base rates established in the Commission's order in docket 6680-UR-113, dated December 19, 2003, as amended September 30, 2004 and April 14, 2005. Rates are based on an 11.5 percent return on common equity and will be in effect until superseded by an order establishing new rates.

Introduction

WP&L filed an application on September 17, 2004, for authority to increase its electric, natural gas, and Ripon water rates on July 1, 2005. The application included financial data for the test year ending June 30, 2006, indicating revenue deficiencies in the test year for retail electric, natural gas, and Ripon water utility operations. WP&L originally requested a $57,772,000 (7.07 percent) increase for electric operations, a $5,461,000 (1.70 percent) increase for natural gas operations, and a $74,000 (6.69 percent) increase for Ripon water operations.

The above amounts were based on WP&L receiving all of its requested fuel rules increases in rates in docket 6680-UR-113. WP&L's requested rates are based on a 12.0 percent return on common equity.

On September 30, 2004, the Commission amended its Order in docket 6680-UR-113 to authorize an increase in electric rates in 2004 due to an extraordinary increase in fuel costs and authorized final surcharges for retail electric service resulting in an estimated $10,295,000 increase in electric revenues on an annual basis. On April 14, 2005, the Commission issued an Interim Decision and Order in docket 6680-UR-113 to authorize an increase in electric rates in 2005 due to an extraordinary increase in fuel costs and authorized additional surcharges for retail electric service on an interim basis resulting in an estimated $27,437,000 additional increase in test year electric revenues.

On November 1, 2004, WP&L filed its electric, natural gas, and water cost-of-service studies (COSS) and rate design information. On January 31, 2005, WP&L filed additional testimony revising its original request to reflect updated forecasts. Based on the January 31, 2005 testimony, WP&L is seeking a $48,132,000 (5.65 percent) increase for electric operations, a $4,964,000 (1.55 percent) increase for natural gas operations, and withdrew the request for an increase in the Ripon water operations due to agreement between WP&L and the city of Ripon regarding the sale of the Ripon water facility.

On February 8, 2005, a prehearing conference was held to determine the issues to be addressed in this docket and to establish a schedule for the hearing. On April 20, 21, and 22, 2005, technical hearings were held at the Commission. On April 22, 2005, public hearings were held at Fond du Lac, Janesville, and Madison.

On June 14, 2005, the Commission issued an Order approving the sale of WP&L's Ripon water utility assets to the city of Ripon in docket 05-BS-142.

The Commission considered this matter at its open meeting on June 30, 2005.

The parties, for purposes of review under Wis. Stat. §§ 227.47 and 227.53, are listed in Appendix A. Others who appeared are listed in the Commission's files.

Findings of Fact

1. Presently authorized rates will produce the following operating revenues for the test year ending June 30, 2006, which are inadequate for electric and natural gas service and, therefore, unreasonable:

   a. Wisconsin retail electric service, $859,710,000.
   b. Wisconsin retail natural gas service, $261,315,000.

2. The following test year estimated rates of return on average net investment rate base at current rates, subject to the Commission's jurisdiction, are inadequate:

   a. Wisconsin retail electric service, 9.05 percent.
   b. Wisconsin retail natural gas service, 9.39 percent.

3. A reasonable increase in operating revenue for the test year to produce a 10.21 percent return on WP&L's average net investment rate base for Wisconsin retail electric operations is $18,641,000.

4. A reasonable increase in operating revenue for the test year to produce a 10.08 percent return on WP&L's average net investment rate base for Wisconsin retail natural gas operations is $2,035,000.

5. A total company test year estimate of fuel and transmission costs of $606,203,000 is reasonable.

6. A total company test year fuel rules monitoring level of fuel costs of $355,080,765 is reasonable.

7. It is reasonable to calculate the total cost of electric generation from natural gas using the NYMEX futures prices from June 15, 2005.

8. It is reasonable to calculate the total cost of purchased power expense for on-peak energy purchases using the NI Hub on-peak energy prices from June 15, 2005.

9. It is reasonable to allow recovery of the fixed lease payments and associated natural gas supply fixed payments for Sheboygan Falls combustion turbines.

10. It is reasonable to reduce WP&L's filed on-peak purchased power costs based on a modeled heat rate of 10,000 Btu/kWh in the ENPRO economic dispatch model.

11. It is reasonable to estimate MWh sales and revenues for economy Sales for Resale based on average volume and margin from 2001 through 2004 plus an additional 225,000 MWh of Sales for Resale in 2005 that result from WP&L's physical hedges which provide for an additional amount of on-peak energy available for sales for resale.

12. It is reasonable to calculate test year fuel costs by including the RockGen purchased power contract as a resource in the ENPRO economic dispatch model.

13. It is reasonable to continue to authorize WP&L to defer any cost associated with invoking the Direct Load Control Program during the test year until the next rate proceeding.

14. It is reasonable to continue to escrow Network transmission charges, firm transmission wheeling costs; transmission wheeling costs associated with access to economy energy; and any Seams Elimination Charge Adjustment (SECA) charges approved by the Federal Energy Regulatory Commission (FERC) until January 1, 2007, or start of the next base rate order

whichever is earlier. It is reasonable to exclude transmission wheeling charges for access to economy energy from monitored fuel costs.

15. It is reasonable to estimate the Rail Cost Adjustment Factor (RCAF) based on a two-year average and not to include the coal cost changes resulting from the reported second quarter 2005 RCAF.

16. It is reasonable to allow recovery of one half the cost increase proposed by WP&L for the revised price for Petroleum Coke in 2006.

17. It is reasonable not to take into account the cost change in electric fuel costs resulting from the Commission approved gas margin for the generation rate classes GN-9 and GN-10.

18. It is reasonable to require WP&L to defer the difference between the fixed cost charges collected in revenue requirement for the Sheboygan Falls leased facility and the actual fixed lease payments resulting from the Commission decision in docket 6680-CE-168.

19. It is not reasonable to require WP&L to contract for more Powder River Basin coal or to sign longer-term contracts for this coal.

20. It is reasonable to include, in the test year revenue requirement, the monitored fuel costs from July 2005 through June 2006. Appendix D shows the monthly fuel costs for monitoring purposes for the test year.

21. It is reasonable to continue monitoring the fuel costs using the following ranges: plus or minus 10 percent monthly; cumulative ranges of plus or minus 10 percent for the first month, plus or minus 6 percent for the second month, and plus or minus 3 percent for the remaining months of the year; and plus or minus 3 percent for the annual range.

22. A reasonable forecast of Wisconsin retail electric miscellaneous operating revenues for the test year is $5,221,000.

23. It is reasonable to authorize recovery of economic development costs related to customer assistance and business/load retention totaling $279,000 on a Wisconsin retail basis.

24. It is reasonable to require WP&L to provide a detailed explanation of economic development activities in its next rate proceeding, including how its participation assisted in economic development efforts in its service territory, and to quantify the direct and substantial benefits realized by ratepayers.

25. It is reasonable to reflect the revenue requirement impact of the sale of the Kewaunee Nuclear Power Plant (KNPP) for purchased power expense, nuclear operations and maintenance (O&M) expenses, nuclear plant depreciation, amortization of nuclear fuel, changes in net investment rate base, and cost of capital structure estimated at a reduction to retail revenue requirement in the test year of $3,593,000 on a retail basis.

26. It is reasonable for the Wisconsin retail portion of the non-qualified decommissioning fund estimated at a retail value of approximately $56 million to be amortized over two years with a true-up for the actual fund balance that is liquidated at the end of the second year. A reasonable test year amortization of the nonqualified decommissioning fund in this proceeding is $28,149,000 on a Wisconsin retail basis.

27. It is reasonable to authorize WP&L to liquidate the nonqualified decommissioning fund to accommodate the amortization over a two-year period.

28. It is appropriate to continue deferring net gains, losses, and transaction costs related to the sale of KNPP until the next rate proceeding when the amounts are certain and after the transaction sales costs have been reviewed.

29. It is reasonable to deny recovery of the pre-construction costs for mercury reduction and fish protection projects in this proceeding.

30. It is reasonable to authorize recovery of the O&M expense and amortization of deferred costs related to the Project Development and Services Agreement resulting from the Sheboygan Falls project approved in dockets 6680-CE-168 and 6680-AE-108.

31. It is not reasonable to include WP&L's updated pension and benefits expense in revenue requirement.

32. It is reasonable to estimate the uncollectible accounts expenses using a four-year average ratio of bad debts to sales revenues applied to forecasted test year revenues excluding adjustments to final revenues in this proceeding.

33. It is reasonable for WP&L to recover the portion of its projected test year incentive compensation costs that are based on non-financial factors at a 75 percent forecasted payout rate.

34. It is not reasonable to reallocate common plant and expenses to electric and natural gas operations due to the sale of the Ripon water operations.

35. It is reasonable to continue deferral of the 2004 KNPP outage costs until WP&L's next rate proceeding.

36. It is reasonable to deny rate recovery for the tax research costs related to research and development tax credits that WP&L has incurred.

37. It is reasonable not to assess a prudence penalty against the company's revenue requirement for the difference in the cost of a generation expansion plan that includes a coal unit by 2008 versus coal in 2011.

38. It was appropriate for WP&L to begin amortization of actual expenditures for manufactured gas plant (MGP) site cleanup during its rate freeze. Commission staff's review of deferred MGP site cleanup costs is not required prior to the start of the amortization. Commission staff's review of deferred MGP site cleanup costs is required before the amortization expense can be recovered from ratepayers.

39. It is reasonable that the MGP amortization expense for the test year ended June 30, 2006, should be $472,000, and at July 1, 2005, the remaining amount of MGP cleanup costs deferred through 2004 to be recovered from WP&L's retail gas ratepayers is about $2,138,000.

40. It is reasonable to increase the retail gas revenue requirement by $43,000, charging Account 408, to reflect the Kansas property tax assessment of gas stored underground in the state of Kansas.

41. It is reasonable for WP&L to work with Commission staff to modify its treatment for stored gas so that it is more in line with the practice of other utilities.

42. It is reasonable to modify the Gas Cost Recovery Mechanism (GCRM) as discussed in the Opinion section.

43. It is reasonable to include a reduction to electric retail revenue requirement of $124,000 for the Sulfur Dioxide Incentive.

44. It is reasonable for WP&L to defer the revenue requirement impacts of all recoveries and incremental costs associated with the potential settlement of a claim for damages filed by Wisconsin Public Service Corporation (WPSC) over a dispute for the storage of spent nuclear fuel with carrying costs at the authorized pre-tax weighted average cost of capital.

45. It is reasonable to continue deferring the revenue requirement impacts of the American Jobs Creation Act of 2004 until WP&L's next rate proceeding.

46. A reasonable level of Wisconsin retail expensed conservation costs recoverable in rates for the test year is $25,329,956 for electric utility operations and $6,680,272 for natural gas utility operations. The level for retail electric operations consists of the conservation budget of $22,864,363, including $8,342,576 for the return on Shared Savings, $11,611,292 to the Wisconsin Department of Administration (DOA) to fund public benefits, $2,000,000 for farm rewiring programs, plus an escrow adjustment of $2,465,593, which represents the test year portion of the projected overspent escrow balance at June 30, 2005 amortized over 42 months. The level for natural gas operations consists of the conservation budget of $5,262,717, including $1,719,631 for the return on Shared Savings, $3,348,393 to the DOA to fund public benefits, plus an escrow adjustment of $1,417,555, which represents the test year portion of the projected overspent escrow balance at June 30, 2005, amortized over 42 months.

47. It is reasonable to adjust the conservation escrow balances for disallowed advertising of $145,350 for electric operations and $25,650 for natural gas operations.

48. It is reasonable to allow a current return on 50 percent of construction work in progress (CWIP) for electric and natural gas operations when determining the return on net investment rate base in this proceeding. It is reasonable for the remaining CWIP to accrue allowance for funds used during construction (AFUDC) at the adjusted weighted cost of capital.

49. Reasonable inflation rates to use for 2005 and 2006 are 2.9 percent and 2.3 percent, respectively.

50. A long-term range of 47.5 percent to 54.0 percent for WP&L’s common equity ratio, on a financial basis, is reasonable and provides adequate financial flexibility.

51. It reasonable not to establish, at this time, a specific target level for the test year average common equity measured on a financial basis.

52. A reasonable estimate of the debt-equivalent of WP&L's off-balance sheet obligations associated with leases and purchased power agreements, including off-balance sheet obligations associated with the KNPP purchased power agreement and the Sheboygan Falls lease, to be imputed into the financial capital structure for the test year is $347,750,000.

53. A reasonable financial capital structure for the test year consists of 53.14 percent common equity, 3.02 percent preferred stock, 21.17 percent long-term debt, 4.38 percent short-term debt, 17.48 percent debt-equivalents of off-balance sheet obligations, and 0.81 percent advances from associated companies.

54. It is reasonable to revise WP&L's dividend restrictions to be based on the financial capital structure in this proceeding and to set the dividend restriction at $92,264,000.

55. It is reasonable to require WP&L to submit a ten-year financial forecast in its next rate proceeding.

56. It is reasonable to require WP&L to submit in its next rate proceeding, detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent.

57. A reasonable utility capital structure for ratemaking for the test year consists of 61.75 percent common equity, 4.04 percent preferred stock, 28.34 percent long-term debt, and 5.87 percent short-term debt.

58. A reasonable interest rate for short-term borrowing through commercial paper is 3.90 percent for the test year.

59. A reasonable interest rate for any long-term debt to be issued in 2006 is 5.65 percent.

60. A reasonable interest rate for WP&L's variable rate demand notes is 2.55 percent for the test year.

61. A reasonable average embedded cost for long-term debt is 6.55 percent for the test year.

62. A reasonable average cost for preferred stock is 5.52 percent for the test year.

63. A reasonable return on utility common stock equity is 11.50 percent.

64. A reasonable weighted average composite cost of capital is 9.41 percent.

65. It is appropriate for WP&L to earn the same level of return on Shared Savings investments as it does for other utility investments.

66. It is reasonable for WP&L to closely monitor how modifications to its Shared Savings Program have impacted program participation and to analyze program participation data to provide insight regarding changes in the level of free-riders. It is appropriate for WP&L to report on the level of free-riders in the Shared Savings Program in the next rate proceeding.

67. It is not appropriate in this proceeding to require WP&L to take any action regarding true-up mechanisms and performance-based incentives.

68. It is reasonable for WP&L to work with staff to develop measures of success and savings goals for its load management activities, customer service conservation activities, and Shared Savings Program.

69. It is reasonable to consider a range of COSS for purposes of determining electric revenue allocation and setting electric rates.

70. It is reasonable to direct WP&L to identify peak-hour drivers during non-summer months and to submit this information with its next rate case.

71. It is reasonable to direct WP&L to track and forecast Load Management, Conservation, and Shared Savings program expenditures by customer rate tariff class.

72. It is appropriate for WP&L to work with the Commission staff to analyze the standard buyback rate and propose revisions.

73. It is reasonable for WP&L to submit a report to the Commission by January 1, 2006, which provides an analysis of the compatibility of its existing direct load control system and the controlled thermostat direct load control system with the MISO Day 2 energy market, as well as possible changes to these programs.

74. It is reasonable to approve rates for electric service for the test year to achieve customer class changes in revenue as shown in Appendix B.

75. It is reasonable to approve an experimental Load Factor Energy Credit provision for WP&L's Cp-2 customer class as shown in Appendix B.

76. It is reasonable to approve changes to the company's transformer rental charges, as shown in Appendix B.

77. It is reasonable to utilize all the natural gas COSS as guides to revenue allocation and rate design.

78. It is reasonable to merge WP&L's three firm commercial classes with its four interruptible commercial classes to form six new firm distribution classes based on customer usage levels.

79. It is reasonable to create two new generation classes.

80. It is reasonable to authorize the natural gas rates shown in Appendix C.

81. It is reasonable to amend the transportation tariffs and the curtailment plan to reflect the elimination of interruptible distribution service, as well as the new commercial and generator classes.

82. It is reasonable to establish a Lost and Unaccounted for Gas Factor.

83. It is reasonable to change the tariff base gas pressure to 7” of water column above the atmospheric pressure.

84. At this time, it is reasonable to make no changes in the WorryProof Bill (WPB) program.

85. It is reasonable that the costs associated with accepting credit card payments are borne by the users.

Conclusions of Law

The Commission concludes it has jurisdiction under Wis. Stat. §§ 1.12, 196.02, 196.025, 196.03, 196.19, 196.20, 196.21, 196.37, 196.374, 196.395, and 196.40 and Wis. Admin. Code chs. PSC 113, 116, 134, and 185 to enter an order authorizing WP&L to place in effect the rates and rules for electric and natural gas utility service set forth in Appendices B and C, and the fuel cost treatment set forth in Appendix D, subject to the conditions specified in this Final Decision.

Opinion

WP&L is a public utility, as defined in Wis. Stat. § 196.01(5), operating as an electric and natural gas and water utility in Wisconsin. Its territory extends across the southern portion of the state from Grant County on the west to Walworth County on the east and extends generally northward through the central part of the state to Wood County and Menominee County. WP&L is a wholly-owned subsidiary of Alliant Energy Corporation.

WP&L provides service to approximately 435,000 retail electric customers, 167,000 natural gas customers, and 2,900 water customers. Among the cities served with electricity are Beloit, Janesville, Sheboygan, Fond du Lac, Beaver Dam, Portage, and Monroe. Cities provided with natural gas utility service include Beloit, Janesville, Fond du Lac, Beaver Dam, Ripon, Stoughton, and Portage. The water utility serves the city and town of Ripon. Upon consummation of the sale of the Ripon Water Utility facilities to the city of Ripon as authorized in docket 05-BS-142, WP&L will no longer provide water utility service.

WP&L also sells electricity at wholesale rates to numerous utilities and cooperatives for resale. FERC regulates these wholesale sales that, therefore, are not affected by these proceedings.

WP&L owns South Beloit Water Gas and Electric (SBWGE), which operates as an electric, natural gas, and water utility in South Beloit, Illinois, immediately adjacent to the Wisconsin border. This subsidiary's electric and natural gas requirements are supplied by WP&L.

Electric Fuel Costs

Purchased Power Modeled in ENPRO

In the recent WP&L rate cases and emergency fuel cases, Commission staff and WP&L have used the NI Hub 5x16 on-peak energy future prices[1] as the cost estimate for on-peak energy purchases. WP&L's ENPRO model inputs have purchased power modeled at blocks of available power at differing heat rates to dispatch and price purchased power from the energy market. WP&L believes that this method of modeling purchased power at varying blocks with different

[1] The NI Hub 5x16 on peak energy price is the reported monthly future price for a 5 weekday, 16 hours on peak product sold in the energy market.

heat rates will more accurately reflect energy market dynamics and generating unit dispatch than the method employed by the Commission staff.

The use of the varying heat rates proposed by WP&L will result in an average price of on-peak power that is greater than the NI Hub futures prices for the 5x16 on-peak energy product. Commission staff adjusted the heat rates for each block of available power to the same uniform 10,000 btu/kwh to make the cost of purchased power for on-peak energy to match the NI Hub futures price plus a $3 per MWh adder for the 5x16 on-peak energy product.

Using varying heat rates or prices will better match the varying cost of purchased power, but using the heat rates proposed by applicant with the NI Hub prices for 5x16 on-peak energy purchase product will overstate purchased power cost for the 2005/2006 test year because the heat rates proposed by WP&L are not symmetrical around a 10,000 btu/kwh heat rate.

It is appropriate to model all blocks of purchased power in ENPRO at 10,000 btu/kWh so that the average cost on-peak purchase match the futures cost estimate of the NI Hub 5x16 on-peak energy product. The use of the NI Hub prices for the estimate of on-peak energy for the test year will reasonably correct for the variability of on-peak energy costs resulting from different monthly forecasts of on-peak energy prices.

Sales for Resale

In recent history the Commission has approved sales for resale (SFR) volumes based on historical levels and also the historical “margin” on SFR which is the difference between the energy-only SFR revenues per MWh and the energy-only purchased power costs per MWh.

WIEG presented testimony that WP&L’s contracted hedge transactions in 2005 for on-peak purchased power resulted in lower amounts of coal-fired generation at Nelson Dewey Units 1 and 2 and Edgewater Units 3 and 4. WIEG argued that sales for resale should be increased to sell the coal-fired generation at Nelson Dewey and Edgewater Units 3 and 4 made available for sale by the purchased power hedging transaction. WIEG stated that, given the volume of purchased power acquired by WP&L in 2005, it was not reasonable to limit sales for resale to historical levels.

In response, Commission staff proposed an increase in the volume of on-peak SFR for 2005 of 591,000 MWh, which is approximately 225,000 MWh greater than the 2001-2004 historical average. This increase in SFR is less than half the contracted on-peak purchased power hedge of significantly more than 500,000 MWh. For 2006, Commission staff's proposes economy SFR is based on 2001-2004 historical average volume and margin. The impact of this proposed adjustment for the 2005-2006 period is a decrease in fuel costs of approximately $1.7 million. Considering historical volumes and margin, and reviewing the appropriate classification for SFR (fixed sales vs. economy sales) Commission staff also proposed a $1.4 million adjustment to WP&L's filed SFR estimate.

It is reasonable to estimate test year SFR based on the historic 2001-2004 average volume and margin plus an additional 225,000 MWh above this average in 2005 to reflect additional energy available to be sold resulting from WP&L's contracted purchased power hedges, resulting in a $3.1 increase in SFR revenues above WP&L's filed estimate.

RockGen in ENPRO Model

Due to its initial tenuous economic viability, the Commission staff has monitored the impacts of the RockGen purchased power contract since the first fuel rate proceeding in which the cost of the contract was proposed to be collected from WP&L ratepayers. Commission staff ran the ENPRO model with and without the RockGen Contract capacity included as a WP&L

energy resource. Removing the RockGen contract from the ENPRO model lowered fuel costs by $1.3 million dollars.

In an economic dispatch model, adding resources should lower economic dispatch costs and removing a resource should increase fuel costs. Therefore, removing the RockGen contract capacity from WP&L resources resulted in a non-intuitive decrease in test year fuel costs.

WP&L testified that an energy resource should not be included or excluded as a resource in the ENPRO model based upon how the model results vary.

It is not reasonable to exclude the RockGen Contract capacity from the ENPRO model at this time without a better understanding of why its removal produces counter-intuitive results. Therefore, the test year estimate of fuel costs should be based on including all resources available to WP&L in the ENPRO model including the RockGen contract. In the event similar results are obtained in the future, the applicant shall work with staff to obtain better information regarding these results.

Sheboygan Falls Capacity Costs

WP&L's filed purchased power capacity included the proposed lease payment associated with the leased Sheboygan Falls facility. The test year revenue requirement for this capacity was based on the 12 monthly lease payments from July 1, 2005 through June 30, 2006. WP&L included all other costs based on 50 percent of 2005 costs and 50 percent of 2006 costs except for escrowed and deferred costs.

Commission staff excluded the costs associated with the Sheboygan Falls facility from the test year revenue requirement pending the Commission decision in docket 6680-CE-168. The Commission approved the Sheboygan Falls lease facility on May 18, 2005.

The cost increase for including the Sheboygan Falls leased facility in the test year revenue requirement depends on whether the capacity costs for 2005-2006 are included on a 50/50 basis or the estimated purchased power capacity for the 12 months from July 2005 through 2006 is used.

Even though other fuel costs are based on a 50/50 test year split, WP&L requested that the Sheboygan Falls fixed payments be calculated using the 12 months from July 2005 through June 2006 because the Sheboygan Falls lease facility will not be in service until approximately June 1, 2005. If the test revenue requirement was calculated based on a 50/50 test year split, a portion of annual Sheboygan Falls fixed lease payments would not be included in test year revenue requirement even though Sheboygan Falls facility should be available for the whole test year period.

It is reasonable to include the fixed lease payments for the Sheboygan Falls facility based on the lease payments and gas supply fixed payments from July 2005 through June 2006. Test year monitored fuel costs should be reduced to reflect energy savings for including the Sheboygan Falls facility in the ENPRO model.

The actual lease cost for the Sheboygan Falls facility is not known. Based on the Commission decision in 6680-CE-168; the fixed cost changes will be adjusted to reflect the actual cost of installation up to the approved cap on the cost to install the turbines. It is reasonable to require WP&L to defer the difference between the fixed costs included in revenue requirement and the actual fixed costs using the actual installation costs of the leased facility.

Rail Cost Adjustment Factor

A published index rail cost adjustment factor (RCAF) indicates the quarterly change for the cost of rail transportation. WP&L proposed using data for two years to project the rail cost applicable for the test year. Later, with the actual second quarter 2005 RCAF available, WP&L requested to increase its test year estimate to reflect this actual second quarter 2005 RCAF of 3.8 percent.

WP&L and WIEG disagree about the continued higher percent growth of the RCAF in the near future. WIEG believes the recent higher RCAF changes are primarily the result of higher diesel fuel costs which could reverse and result in a lower RCAF. WIEG also testified that using a five-year average is a more appropriate basis for projecting the test year level than WP&L's proposed use of data from two years.

Commission staff presented the alternative of using the two year average of the RCAF changes but without further updates for the actual second quarter 2005 RCAF.

The two year average is more representative of likely test year levels and is therefore a reasonable basis for the test year estimate. Further updating this estimate for the second quarter of 2005 is not reasonable because it undermines the use of averaging.

Petroleum Coke

WP&L stated it is appropriate to include the updated estimate for petroleum coke in the test year revenue requirement because its original filing did not include petroleum coke as a fuel source at the Nelson Dewey plant and at the time of the audit it did not have the market research for an accurate price estimate for this fuel. WP&L provided the Commission staff with a preliminary price estimate but stated the price could be much higher. At the hearing WP&L stated it has conducted research concerning the price of petroleum coke in 2006 and the delivered cost to Nelson Dewey would be $1.0 million higher than included in the Commission staff estimate. The test year cost increase effect would be about one half the 2006 proposed increase in fuel costs.

WIEG stated fuel costs should not be increased for petroleum coke because there is no transparent market price to check the WP&L estimate, and other rate case costs may result in offsetting savings if the rate case audit was restarted now.

Since both positions are compelling, it is reasonable to include half the test year estimate, or $250,000 in revenue requirement.

Updated Electric Costs for Approved Gas Margin Changes

WP&L requested that the monitored fuel costs be updated to reflect the Commission approved margin for natural gas generation classes GN-9 and GN-10. WP&L states that Commission staff has proposed margin rates above those included in both WP&L's and Commission staff's electric fuel costs. The Commission has taken into consideration the margin increases approved in the natural gas rate designs in test year fuel costs in other rate proceedings.

Test year fuel costs should not be updated to reflect the natural gas margin approved by the Commission in this proceeding. The change in approved gas margin for the GN-9 and GN-10 rates is not material enough to reflect in the final fuel costs for electric generation.

Powder River Basin Coal Procurement

WIEG stated that the Commission should direct WP&L to contract for additional Powder River Basin (PRB) coal because many experts are predicting an increase in price in PRB coal similar to other fossil fuels. WIEG states that WP&L should take advantage of the current low PRB coal price by entering into longer-term contracts for both its open requirements and supplies for future years. WIEG believes that WP&L can avoid the effects of looming market price increases.

WP&L has been buying PRB coal using a portfolio procurement approach, with varying terms including purchases of spot market coal to contracts of several years, and believes that doing as proposed by WIEG would be trying to time the market. WIEG's proposal goes against WP&L's current stair-stepped, staggered-term, dollar-cost averaging portfolio approach.

It is not necessary to direct WP&L to sign longer-term PRB coal contracts. It is WP&L's management requirement to prudently contract for coal supplies for its electric generation, which will continue to be closely monitored by Commission staff.

Monitored Fuel Costs for a Split Test Year

WP&L's filed monitored fuel costs included in revenue requirement were based on a 50/50 split of 2005 and 2006 estimated fuel costs. The fuel cost shown for monitoring purposes was for the 12 months from July 2005 through June 2006.

WIEG stated that Wis. Admin. Code § PSC 116.04(1) requires the annual tolerance be measured on a calendar year basis. Since WP&L is required to use a calendar year basis and fuel costs should match the period the fuel are forecast, WP&L should be required to use a calendar year estimate of fuel costs in its rates. WIEG proposes that the Commission authorize two complete 12-month monitored fuel costs for 2005 and 2006. A step increase could be determined by the cost difference between the two calendar year forecasts.

WP&L stated the method it used for including monitored fuel costs in test year revenue requirement is a 50/50 basis and monitoring fuel costs based on the 12 months beginning July 2005 is appropriate. WP&L argues that including the fuel cost estimate in revenue requirement based on the July 2005 through June 2006 fuel costs will include a full KNPP planned outage in rates for 2004, 2005 and 2006. To eliminate the concern of collecting additional fuel costs for the KNPP planned outage for the first half of 2006, WP&L proposed a simple split of 2005 and 2006 fuel costs for the test year revenue requirement.

If fuel costs are monitored on a 12-month basis that is not a calendar year, Commission staff stated that the fuel costs included in revenue requirement should be the monitored fuel costs from July 2005 through June 2006. This would match the fuel costs collected from ratepayers with the monthly monitored fuel costs. If fuel costs are to be monitored on calendar basis, a biennial process with a step increase proposed by WIEG may be necessary.

It is reasonable to match fuel costs with the test year revenue requirement. The fuel rules do not require fuel costs to be monitored on a calendar year basis. It is appropriate that monitored fuel costs included in revenue requirement reflect the July 2005 through June 2006 fuel costs to match the monthly fuel costs that will be monitored, as shown in Appendix D.

Summary of Electric Fuel Costs

The total company test year electric fuel, capacity and transmission cost of $606,203,000 reflects the cost of generation, purchased capacity, transmission wheeling, network transmission service, and purchased energy, less the revenue from opportunity sales of energy and capacity.

The total cost of natural gas-fired electric generation is based on the NYMEX figures price from June 15, 2005, and forecasted NI Hub on-peak purchased power prices based on forward pricing and the average of actual on-peak energy prices reported as of June 15, 2005.

Monitoring of electric fuel costs

This is WP&L's first rate case since the modification of the fuel rules in docket 1-AC-197. Monitored fuel costs include only the cost of fuel itself and purchased power energy. Any purchased capacity costs that are required to meet reserve requirements are excluded from monitoring and may only be adjusted in a base rate case. Firm transmission costs associated with these capacity purchases are also excluded. For this proceeding, the transmission charges associated with access to economy energy are excluded from monitored fuel costs. Fuel and ash handling, and sulfur dioxide (SO_2) allowance costs are excluded as well. Based on information in the record, a reasonable test year monitored fuel cost is $350,080,765. The test year fuel cost divided by the test year estimate of net native energy requirements of 15,333,219 MWh results in an average net fuel cost of $0.02316 per kWh. Appendix D shows the monthly fuel costs to be used for monitoring purposes.

Under Wis. Admin. Code § PSC 116.04, the Commission establishes monthly and annual ranges for monitoring the test year fuel forecasts. The following variance ranges are reasonable for monitoring WP&L's fuel costs: (1) for the annual range, plus or minus 3 percent; (2) for the monthly range, plus or minus 10 percent; and (3) for the cumulative range, plus or minus 10 percent for the first month of the year, plus or minus 6 percent for the second month, and plus or minus 3 percent for the remaining months of the year. The method of applying those ranges, established in prior Commission decisions for WP&L, shall continue to be used and applied, using the data in Appendix D for monitoring fuel costs.

Electric Miscellaneous Operating Revenues

WP&L used an average of the last five historical years (1999-2003) which results in forecasted miscellaneous joint electric operating retail revenues of $4,576,000. Commission staff proposed using an adjusted average of the last three historical years (2001-2003) which results in forecasted miscellaneous joint electric operating Wisconsin retail revenues of $5,221,000.

WP&L testified that using the five-year average is appropriate because that methodology was used in dockets 6680-UR-111 and 6680-UR-112, and the method used to forecast miscellaneous revenues should be consistent in each rate case.

Commission staff used the most recent adjusted three year average to forecast test year electric miscellaneous operating revenues because it reflected the most recent trend and the goal is to make as realistic estimates as possible for the representative test year period. This method of forecasting miscellaneous operating revenues achieves the goal of reasonable forecasts for future costs and is appropriate.

Economic Development and Sales Promotion Costs

WP&L requested recovery of economic development expenses amounting to $667,000. Commission staff's audit found this amount to include costs related to economic development and sales promotion along with the portion of the technical and integrated services that are allocated to the business development budget. Commission staff excluded the entire amount based on prior Commission determinations for similar expenses.

WP&L subsequently requested that the portion of its economic development programs that are either customer assistance or business/load retention activities be included in rates. These activities are consistent with Governor Doyle's "Grow Wisconsin" initiative.

The Commission finds it appropriate to include $279,000 in Wisconsin retail revenue requirement for economic development expenses limited to customer assistance and business/load retention activities. WP&L is required to provide a detailed explanation of its actual economic development activities in its next rate proceeding, including how its participation assisted in economic development efforts in its service territory, and to quantify the direct and substantial benefits realized by ratepayers.

Sale of KNPP to Dominion Energy Kewaunee, Inc.

The Commission approved the transfer of ownership and operational control of the KNPP to Dominion Energy Kewaunee Inc. (DEK) subject to conditions in its order issued on April 21,

2005. The consummation of the sale occurred on July 5, 2005. It is reasonable to reflect the revenue requirement impact of the sale of KNPP in this proceeding for purchased power expense, nuclear operations and maintenance expenses, nuclear depreciation, amortization of nuclear fuel, and changes in net investment rate base and cost of capital structure, estimated at a reduction to retail revenue requirement in the test year of $3,593,000 on a retail basis.

In its final decision in docket 05-EI-136, the Commission determined it is reasonable and prudent for the applicants, including WP&L, to retain their respective nonqualified decommissioning funds, for such funds to be released from dedication to the future decommissioning of the KNPP upon closing of the transaction, and for the applicants to return these funds to their ratepayers on an amortized basis. It also determined that the specific amortization and jurisdictional allocations would be determined in specific rate proceedings and that it is reasonable, prudent, and in the public interest to defer all gains, losses, and transaction costs as described in the final decision in docket 05-EI-136. WP&L proposed to return the nonqualified decommissioning funds, netted against any net gain or loss on the sale of KNPP, over eight and one half years, the remaining life of the purchased power agreement because the negotiation resulting in the sale of KNPP related to the analysis of current cash flows and asset transfers as well as future cash flows and asset transfers. The Citizens' Utility Board (CUB) proposed to reconvene after the sale of KNPP is consummated and then return the nonqualified decommissioning fund as a special bill credit over two years with a true-up at the end of the second year. WIEG proposed that the Commission use the next rate proceeding or a new docket to determine the appropriate method of returning the nonqualified decommissioning fund to ratepayers and if that decision is made in this proceeding that the fund should be returned to ratepayers over two years.

The return of the nonqualified decommissioning funds in question in this proceeding were paid by WP&L ratepayers for the sole purpose of ensuring sufficient funds would be available to decommission KNPP in the future. Since the disposition of these funds was an essential component of the KNPP sale and that is now consummated, those funds should be returned to ratepayers as soon as practicable. For purposes of this proceeding, it is reasonable for the retail portion of the funds estimated at a Wisconsin retail value of approximately $56 million to be amortized over two years with a true-up for the actual fund balance that is liquidated at the end of the second year. A reasonable test year amortization of the nonqualified decommissioning fund in this proceeding is $28,149,000 on a Wisconsin retail basis.

Since the sale was not consummated until July 5, 2005, and the net gains, losses, and transaction costs of the sale have not been determined or reviewed in this proceeding, it is appropriate to continue deferring such amounts until the next rate proceeding when the amounts are certain and after the transaction sales costs have been reviewed. It is also appropriate to address the difference between straight-line and accelerated depreciation used for KNPP after the steam generator replacement in the next rate proceeding when the overall net gain or loss on the sale is addressed.

WP&L filed its case in this proceeding with the assumption that the nonqualified decommissioning fund would remain in an external fund and earn its own return. When discussions on the record of returning the nonqualified fund over a shorter period of two years occurred, WP&L requested that it be authorized to liquidate the nonqualified fund as presented in the sale proceeding. Since the consummation of the sale occurred on July 5, 2005, and the nonqualified fund is to be returned to ratepayers over two years, it is reasonable to authorize WP&L to liquidate the nonqualified decommissioning fund.

Pre-certification and Pre-construction Costs for Baseload Plants

WP&L forecasted pre-certification expenses in this case of $2,558,000 on a total company basis, for two new baseload plants, one in 2010 with WPSC, and the other for a 2012-2013 time period. Commission staff excluded these expenses from its forecasted revenue requirement because of the uncertainty as to whether they would be financed as rate base projects versus leased generation projects, along with the uncertainty of the forecasted expenses, and uncertainty of the ownership percentage of the plant to be shared with WPSC. Commission staff also excluded $4,758,000 of construction expenditures that WP&L forecasted in the test year for the 2010 baseload plant.

WP&L believes that baseload plant costs should be included in revenue requirement but that the regulatory treatment of deferred costs that was granted to WPSC in docket 6690-UR-116 would also be logical for these baseload plant expenditures. On April 4, 2005, WP&L submitted a deferral request in docket 6680-GF-114, requesting authorization to defer the retail portion of incremental pre-certification and pre-construction costs for the two baseload plants including carrying costs on the deferred pre-certification costs at its most recently authorized pre-tax weighted cost of capital and accrual of allowance for funds used during construction on 100 percent of pre-construction costs. On June 13, 2005, the Commission issued an order granting deferred accounting treatment for the pre-certification and pre-construction costs that are incurred on or after June 2, 2005 for these two baseload plants as WP&L requested. This treatment is similar to the treatment afforded Wisconsin Public Service Corporation for its share of the 2010 baseload plant.

Sheboygan Falls Operating Expenses and Deferred Costs

On May 18, 2005, the Commission issued a final decision approving a leased generation contract between WP&L and Sheboygan Power, LLC and issued a Certificate Authority (CA) to operate and a Certificate of Public Convenience and Necessity for the electric generation facility (Sheboygan Falls) in docket 6680-CE-168.

The test year forecasted annual operating and maintenance expenses resulting from docket 6680-CE-168 of approximately $1,722,000 on an electric retail basis are reasonable to include in test year revenue requirement. Deferred pre-construction costs and carrying costs of $4,792,000 that are related to the Project Development and Services Agreement (PSDA) as adjusted to correct an error in the calculation of the deferred carrying costs and to account for the reduction of $11,217,085 on the price of the turbines ordered by the Commission in dockets 6680-CE-168 and 6680-AE-108, are reasonable to include in test year revenue requirement. It is reasonable to amortize such amount over 42 months resulting in a test year amortization amount of $1,369,000 on an electric retail basis.

Pension and Benefits Expense

WP&L contends that it has experienced a material change to its revenue requirement due to pension and benefit costs and estimates the impact will increase retail electric and gas revenue requirements by $1,621,000 and $383,000, respectively. These forecasted cost changes were provided after Commission staff completed its audit. The retail electric and natural gas pension and benefit expenses in question excluding the requested increases are approximately $19 million and $4.5 million respectively.

WP&L believes that the updated pension and benefits costs are outside its control and the trend for these costs has been increasing for WP&L (and all employers). It also believes that to deny recovery of necessary costs to provide utility service based on the timing of when such amounts are known is inconsistent with setting fair and reasonable rates based upon the anticipated costs to provide utility service.

The pension and benefits cost changes forecasted by WP&L were provided after Commission staff completed its audit. Ordinarily, unless there are particularly compelling and unusual circumstances, the auditing staff applies a general policy of not changing its revenue requirement for information provided after the Commission staff's audit is complete. After the audit it is expected that some estimates will increase, however the increases are expected to be offset by decreases in other areas. It would not be good practice to review and incorporate a late increase, while ignoring other areas where staff may, in an extended review, conclude that an estimate should be reduced.

Exceptions to this general policy are to correct mathematical errors, incorporate the effects of new laws adopted, and reflect new estimates for items that are recognized as contingent on later events that resolve or reduce the uncertainty of the original estimates. In this case, none of the exceptions apply directly. It is therefore appropriate to deny recovery of WP&L's updated forecast of pension and benefits expense.

Uncollectible Account Expenses, Credit Activity Data Collection, and Customer Assistance Plus (CA+) Program Review

WP&L requested recovery of close to $4.8 million in uncollectible account expenses. Commission staff proposed a decrease to WP&L's forecasted electric related uncollectible account expenses on a retail basis in the amount of $667,000 and an increase to the natural gas related uncollectible account expenses on a retail basis in the amount of $241,000 based on the most recent four year historical average ratio (2000-2003) of bad debts expense to sales revenues applied to Commission staff's forecasted revenues at present rates, which results in a forecast of test year uncollectible accounts expense of approximately $4.4 million. WP&L does not contest Commission staff's method of forecasting uncollectible expense. However, WP&L requested that the forecast of uncollectible accounts expenses be updated to reflect final revenues determined in this proceeding because it believes to exclude such amounts would result in an improper matching of estimated revenues during the test year with reasonable estimates of expenses for the test year including bad debt expense.

CUB testified that inadequacies with WP&L's credit and collection programs and its low-income/Early Identification Program (EIP), CA+ have contributed to the level of WP&L's bad debt expenses and believes that 2003 uncollectible accounts expense should be excluded from the historical analysis. CUB proposed a decrease to WP&L's forecasted electric related uncollectible account expenses on a retail basis in the amount of $1,237,000 and an increase to the natural gas related uncollectible account expenses on a retail basis in the amount of $90,000 based on the four year historical average ratio (1999-2002) of bad debts expense to sales revenues applied to Commission staff's forecasted revenues at present rates. CUB also recommended that the Commission direct WP&L to collect and report data to the Commission regarding its collection activities and use an independent contractor to evaluate its CA+ program.

WP&L testified that most of the information that CUB recommended that they should report is already available for reporting by WP&L, but questioned its value in managing or evaluating its collection operations. WP&L argued that its CA+ program meets its original and on-going intent: providing customers with budget and energy use counseling and referral to other agencies for financial assistance. The company did not believe that costs associated with expanding its CA+ program should be borne by its ratepayers.

There is no information presented that would support requiring the imposition of data reporting requirements solely on WP&L or that indicated the need for an independent contractor to evaluate WP&L's CA+ program. The Commission directed the Division of Water, Compliance, and Consumer Affairs and the Gas and Energy Division to take note of the data reporting required in states such as Maine, Pennsylvania, and Iowa and monitor the uncollectibles situation with WP&L and the other large utilities.

Based on the record in this proceeding, the Commission finds that the staff method of forecasting uncollectible accounts expense is reasonable. Consistent with recent decisions in the Madison Gas and Electric Company and WPSC rate proceedings, it is not appropriate to adjust the uncollectible accounts expense for adjustments to final revenues because the Commission has made it a practice to refrain from cascading adjustments when determining the final revenue requirement based on the Commission's decisions.

Management Incentive Compensation

WP&L requests recovery in this proceeding of incentive compensation costs as part of a competitive total compensation package. WP&L's management incentive plans are based on such factors as earnings per share, compliance with business unit budgets, customer satisfaction, safety, environmental, diversity, and other individual, business unit, and corporate factors.

WP&L has not demonstrated that the achievement of financial objectives (earnings per share and compliance with business unit budgets) provides a direct benefit to customers. Lacking a showing of direct benefit to customers, recovery from ratepayers of the costs associated with these incentives is inappropriate. Therefore, the revenue requirement in this proceeding shall not include incentive costs based on financial objectives. However, incentive compensation costs based on non-financial factors such as customer satisfaction, safety, and environmental goals may be reasonable as these factors do represent a direct benefit to customers. Accordingly, authorized rates shall include those incentive costs based on non-financial factors. In addition, a review of the forecasted payouts based on historical payments suggests that the payouts will not occur 25 percent of the time. Therefore it is appropriate to modify the incentive compensation adjustment to incorporate a forecasted payout rate of 75 percent.

Sale of Ripon Water Operations

Commission staff's forecasted revenue requirement does not include any impacts of the Ripon Water Utility sale. WP&L requests that the portion of the common costs allocated to the Ripon Water Utility be reallocated to the electric and natural gas utilities.

The sale of the Ripon Water Utility should result in overall reduced operating costs and therefore reduce the allocation of common costs to the electric and natural gas functions. As a result, it is not appropriate to reflect increases in electric and natural gas utility revenue requirements for the sale of the Ripon Water Utility.

KNPP 2004 Outage Costs

The Commission approved an accounting deferral for the 2004 KNPP outage costs in docket 05-GF-141 in its order issued December 3, 2004. WP&L requests an adjustment to electric revenue requirement to amortize the estimated KNPP deferred operation and maintenance expense associated with the 2004 outage over 18 months.

The Commission finds it is reasonable to continue deferral of the KNPP 2004 O&M outage costs until the next WP&L rate proceeding to allow a full review of such costs in the WPSC rate proceeding in docket 6690-UR-117. In addition, the deferred amounts may be subject to potential recoveries from third parties.

Research and Development (R&D) Credits

WP&L requested an adjustment to electric and natural gas revenue requirement to amortize tax research costs of $208,171 over 30 months for costs it has incurred for tax research related to R&D tax credits.

This Commission has historically supported aggressive tax positions by utility companies with resulting deferral and recovery of such costs in future rate cases. However, the basis for past deferrals related to aggressive tax positions has been to allow costs for taxes and associated interest when unfavorable rulings have been made for the utility, not for consulting fees or other costs not internally budgeted for. The costs incurred that WP&L has requested rate recovery for are not material in nature and do not meet the deferral criteria established in Statement of Position 94-01. The Commission therefore finds it is reasonable to deny deferral rate recovery for the tax research costs related to research and development tax credits that WP&L has incurred.

Storage of Spent Nuclear Fuel

Exelon Corp., the largest operator of nuclear power plants, will be paid as much as $300 million through 2010 by the federal government after settling a dispute over the storage of spent nuclear fuel. WPSC filed a similar claim in 2004. Wisconsin electric ratepayers, including WP&L's, have paid significant amounts into a nuclear waste fund over two decades. If WP&L would receive any settlement, Commission staff proposed that WP&L should be required to defer the revenue requirement impacts resulting from this settlement until a future rate proceeding when the settlement dollars can be returned to ratepayers.

It is reasonable for WP&L to defer the revenue requirement impacts of the potential settlement of a claim for damages filed by WPSC over a dispute for the storage of spent nuclear fuel with carrying costs at the authorized pre-tax weighted average cost of capital.

American Jobs Creation Act of 2004

On October 22, 2004, the American Jobs Creation Act of 2004 (Jobs Creation Act) was signed into law. The Jobs Creation Act, among other things, reduces the corporate income tax on certain manufacturing industries. In its order in docket 05-GF-143, dated December 20, 2004, the Commission directed WP&L and other utilities to defer, with carrying costs at the authorized pre-tax weighted average cost of capital, the revenue requirement impacts resulting from the Jobs Creation Act until future rate proceedings when the impacts are discernable. Since the impacts are not known at this time, it is reasonable that the revenue requirement impacts of the Jobs Creation Act be addressed in WP&L's next rate proceeding.

SO_2 Allowance Incentive Adjustment

The Commission authorized an SO_2 performance based ratemaking process for WP&L in docket 6680-UR-110 in which WP&L collected in rates certain amounts of revenue that it could retain if SO_2 emission limits met certain standards. If such standards were not met, WP&L was required to file an SO_2 emissions report with the Commission and refund such amounts. This process ended with the interim base rate order in docket 6680-UR-111 in April 2002. WP&L filed its SO_2 emission report for 2002 on March 28, 2003, for the period during 2002 that the performance based ratemaking mechanism was in effect indicating a total refund was due to customers of $185,573. Because of the relatively small amount it is appropriate that the refund of $124,000 on a retail basis be included as a reduction to revenue requirement in this proceeding rather than a direct customer refund.

Other Deferrals

As a result of the ratemaking process, and with reasonable assurance by a regulatory commission of future cost recovery, utilities sometimes include allowable costs in a period other than the period in which those costs would be charged to expense by an unregulated enterprise in accordance with Generally Accepted Accounting Principles (GAAP). These differences usually relate to the timing of the recognition of a cost. The result of these timing differences is the creation of deferred accounts. The Commission's policy on deferred accounts is set forth in the Commission's Staff Accounting Policy Team Statement of Position 94-1, approved by the Commission on February 23, 1995. The following is a list of those deferred accounts approved for WP&L, the amortization period, and the amount of Wisconsin jurisdictional 2005-2006 test year amortization expense:

Deferred Accounts	Amortization Period	Test Year Amount	
		Electric	Gas
Sheboygan Falls preconstruction costs	42 months 2005-2008	$1,369,056	$-0-
KNPP GAP costs	18 months 2005-2006	($875,526)	$-0-
KNPP High Pressure Turbines	66 months 2005-2010	$86,247	$-0-
NOX Emission Credit Sales	18 months 2005-2006	($286,772)	$-0-
SO_2 Emissions Credit Sales	18 months 2005-2006	($298,206)	$-0-
NOX costs	18 months 2005-2006	($445,902)	$-0-
Interest on Tax Deficiencies	18 months 2005-2006	($331,329)	$-0-
September 11, 2001 costs	18 months 2005-2006	($594,517)	($11,569)
Sales and Use Tax Settlements	18 months 2005-2006	$782,871	$223,849
Excess PSC AFUDC	16 years	$1,274,511	$110,372
Net Total		$680,433	$322,652

Conservation Budget and Escrow Adjustment

The test year Wisconsin retail escrowed electric utility conservation expense is $25,329,956. This consists of a test year conservation budget of $22,864,363, including $8,342,576 for the return on share savings, $11,611,292 to the DOA to fund public benefits,

$2,000,000 for farm rewiring programs, plus an escrow adjustment of $2,465,593, which represents the test year portion of the projected overspent escrow balance amortized over 42 months. The test year Wisconsin natural gas utility conservation expense is $6,680,272. This consists of the test year conservation budget of $5,262,717, including $1,719,631 for the return on Shared Savings, $3,348,393 to the DOA to fund public benefits, plus an escrow adjustment of $1,417,555, which represents the test year portion of the projected overspent escrow balance amortized over 42 months. Both amortizations shall begin with the effective date of this rate order. The conservation escrow balances were adjusted for disallowed advertising of $145,350 for electric operations and $25,650 for natural gas operations.

Manufactured Gas Plant (MGP) Site Cleanup Costs

Since the costs associated with the clean-up of MGP sites are significant and arise from facilities long removed from utility service, the Commission developed specific policies concerning the recovery of such costs for WP&L in docket 6680-UR-108. The Commission found that sharing of the cleanup costs between ratepayers and shareholders would be achieved by means of deferral accounting, with recovery of deferred cleanup costs (net of insurance and third party recoveries) in rates over a period of five years, but no recovery in rates of the carrying costs on the unamortized balances. In a memo dated December 14, 1993, Commission staff enumerated general guidelines for the accounting of MGP cleanup costs summarizing the Commission’s policy on MGP site cleanup costs. These guidelines have been periodically updated but not materially changed.

The order in docket 6680-UM-100 (merger order) authorized the merger between WPL Holdings, Interstate Power Company, and IES Industries, Inc. with conditions. One of the conditions required WP&L’s retail rates be frozen at [then] current levels for a period of four years from the effective date of the order, November 6, 1997. The merger order directed that the currently established regulatory accounting policy for WP&L's accounting deferrals and amortizations for other than demand side management transactions should continue to apply during the rate freeze period. This meant that actual expenditures for MGP cleanup would be deferred each year and the amortization of those costs would start of the beginning of WP&L's next scheduled biennial test year.

WP&L argued in this proceeding that Commission policy required Commission staff's review of the deferred MGP cleanup costs prior to the start of amortization and prior to the start of recovery in rates. Commission staff's guidelines for the accounting of MGP cleanup costs does not specify that Commission staff's review is needed before the MGP cleanup costs deferred from any year can be amortized; rather, Commission staff's review and Commission authorization is necessary before the amortization expense can be recovered from ratepayers by inclusion in rates. Testimony in the WP&L merger docket made it clear that the Commission's intent was for all regulatory assets and liabilities created during 1996 and 1997 would begin amortization on January 1, 1999, and all regulatory assets and liabilities created during 1998 and 1999 would begin amortization on January 1, 2001. This testimony was consistent with the Commission MGP policies established in docket 6680-UR-108 as well as Commission staff's guidelines for the accounting of MGP cleanup costs.

Reflecting the deferral of MGP site cleanup expenditures through 2004, previous Commission's authorizations for recovery of the MGP amortizations, and the amortization of deferred MGP site cleanup costs from 1996-1999 pursuant to Commission policy, it is reasonable that the MGP amortization expense for the test year ended June 30, 2006, should be $472,000. It is also reasonable that at the start of the test year in this proceeding, the remaining amount of MGP cleanup costs deferred through 2004 to be recovered from WP&L's retail gas ratepayers is about $2,138,000.

State of Kansas Tax on Stored Natural Gas

The 2004 Kansas legislature enacted Senate Bill 147 that allowed for the taxation of gas stored underground in the state of Kansas. Based on the language of SB 147, a reasonable estimate of the tax assessment is about $43,000. The legality of the new Kansas law change is currently being challenged in the courts.

WP&L sought dollar for dollar recovery of the Kansas tax through its GCRM, subject to refund pending the final outcome of the legal challenges to the Kansas law.

Commission staff testified that the Uniform System of Accounts for Private Natural Gas Utilities (USOA) requires that all taxes assessed by state or county authorities should be charged to Account 408, Taxes Other Than Income Taxes. The practice among Wisconsin utilities is that most of the taxes charged to Account 408 are not allocated to other utility accounts including cost of gas.

It is reasonable to increase the retail gas revenue requirement by $43,000, charging Account 408, to reflect the new Kansas tax. The recovery of this tax should not be subject to refund, due to its immateriality.

Inflation rates

A test year revenue requirement based on inflation rates of 2.9 percent for 2005 and 2.3 percent for 2006 is reasonable. The inflation rates are based on the average of current estimates from the monthly publication of Global Insight U.S. Economic Outlooks and Blue Chip Economic Indicators. This is a reasonable and objective method of determining the expected rates of inflation.

Summary of Income Statement

In addition to the specific items discussed above, all other Commission staff estimates and adjustments to the applicant's estimates are reasonable and just. Accordingly, estimates of test year 2005-2006 Wisconsin retail electric and natural gas operations that are considered reasonable and just for purposes of determining the revenue requirement in this proceeding are as follows:

Operating Income Statements

	Retail Electric (000's)	Retail Natural Gas (000's)
Operating Revenues		
Sales	$ 838,131	$ ---
Gas Supply Revenue	---	261,197
Other Operating Revenues	21,579	118
Total Operating Revenues	$ 859,710	$ 261,315
Operating Expenses		
Fuel and Purchased Power	$ 414,044	$ ---
Purchased Gas	---	178,794
Other Production Expenses	9,033	328
Transmission Expenses	68,556	---
Distribution Expenses	27,765	8,221
Customer Accounts Expenses	15,312	5,301
Customer Service Expenses	8,467	1,460
Conservation Expenses	25,330	6,680
Sales Promotion Expenses	---	---
Administrative and General Expenses	51,408	16,708
Total Operation and Maintenance Expenses	$ 619,915	$ 217,492
Depreciation Expense	81,385	14,827
Regulatory Asset Amortizations	556	794
Taxes Other Than Income Taxes	30,700	3,568
State and Federal Income Taxes	47,274	9,147
Deferred Income Tax	(7,411)	(1,011)
Total Operating Expenses	$ 772,419	$ 244,817
Net Operating Income	$ 87,291	$ 16,498

Net Investment Rate Base

WP&L, intervenors, and Commission staff presented testimony and exhibits at the hearing concerning their estimates of WP&L's test year 2005-2006 electric and natural gas net investment rate base. Significant issues pertaining to the net investment rate base are addressed separately below.

Mercury Reduction and Fish Protection Projects

Commission staff excluded construction expenditures from its electric estimates related to the Prairie du Sac fish ladders project of $7,687,000 in 2005 and $205,000 in 2006, and construction expenditures related to mercury requirements of $5,000,000 in 2005 and $20,084,000 in 2006 because they require construction authorizations for which WP&L has not yet submitted a CA application.

WP&L made no showing that it is appropriate to include construction expenditures in electric revenue requirement for mercury reduction and fish ladder projects for which it has not submitted CA applications; therefore, these projects shall not be included in revenue requirement at this time.

Summary of Net Investment Rate Base

For purposes of determining the revenue requirement in this proceeding, a reasonable and just estimate of WP&L's test year average net investment rate base for its Wisconsin retail electric and natural gas operations is as follows:

2005-2006 Test Year
Wisconsin Jurisdictional Net Investment Rate Base

	Retail Electric (000's)	Retail Natural Gas (000's)
Plant in Service	$1,994,842	$ 351,594
Less: Accumulated Depreciation	902,241	187,969
Net Utility Plant	$1,092,601	$ 163,625
Add: Fuel Inventory	11,867	---
Stored Natural Gas	---	25,051
Materials and Supplies	16,516	1,508
Investment in Assoc. Companies	140	---
Less: Customer Advances for Construction	30,118	2,492
Deferred Income Taxes	126,978	11,922
Average Net Investment Rate Base	$ 964,028	$ 175,770

Pro Forma Rate of Return

The estimated operating income for purposes of this proceeding, for the test year ending June 30, 2006, results in a rate of return on net investment rate base of 9.05 percent for retail electric operations and 9.39 percent for natural gas utility operations.

Financial Capital Structure and Dividend Restriction

The long-term range for WP&L's common equity ratio, on a financial basis, found reasonable in WP&L's last rate case, was 47.5 to 54.0 percent common equity, based on guidelines for maintaining an "A" credit rating. In this proceeding, the Commission reviewed two long-term equity range options, as well as WP&L's current range. One alternative would lower the current range based on revised total debt to total capitalization guidelines of Standard and Poor's (S&P) for "A" credit rated utilities. The other alternative would increase the current range to approximate S&P's total debt to total capitalization guidelines for "AA" credit rated utilities. WP&L's ratings are tied to AEC's ratings and to pursue an "AA" rating at this time may not be cost effective for ratepayers. The appropriate guidelines should continue to be set on the basis of an S&P "A" rating and the current long-term range of 47.5 to 54.0 percent for WP&L's common equity ratio, on a financial basis, continues to be reasonable and provides adequate financial flexibility at this time. The exact level of the common equity ratio within that range should not be static, but rather should dynamically reflect the circumstances facing WP&L at a given time.

In docket 6690-UR-116, the Commission selected a target level for the test year average common equity to be used in developing WPSC's test year financial capital structure. After the decisions of the Commission in that docket were incorporated into the test year operations, WPSC's capital structure was balanced through special dividends or equity infusions to ensure that the average test year equity approximated the target established by the Commission. While a proposal to follow the same procedure for WP&L was uncontested by the parties, the Commission determines the record was inadequate on the issue to support a change to this practice for WP&L. It is reasonable not to establish, at this time, a target level for the test year average common equity measured on a financial basis.

Consistent with the Commission's determinations in previous dockets, Commission staff included in the financial capital structure off-balance sheet obligations, including debt-equivalent associated with leases and purchased power agreements. Adjustments for these off-balance sheet obligations are made by S&P and other financial analysts when calculating various financial ratios, including the total debt to capital ratio. The size of the adjustment made by financial analysts, to calculate the debt-equivalent for purchased power and operating leases, was an issue in this docket. All parties agreed that the debt-equivalent should be based on the present value of the minimum fixed payments under the lease or agreement. At issue was the appropriate risk factor to apply to the present value.

WP&L's filing used a 100 percent factor for operating leases and the Sheboygan Falls lease, and a 40 percent factor for its purchased power agreements, including the KNPP purchased power agreement. WIEG questioned the use of the 40 percent factor; arguing that the number was unsupported. While the Commission is concerned with the lack of support for the alternatives suggested, it determines the 100 percent factor reasonable for operating leases and the Sheboygan Falls lease, and the 40 percent factor reasonable for purchased power agreements. Use of these factors produces reasonable estimates of the debt-equivalents of $30,470,000 for all operating leases and $133,679,000 for all purchased power agreements, excluding the KNPP purchased power agreement.

Based on a 100 percent factor, a reasonable estimate of the debt-equivalent associated with the Sheboygan Falls lease is $141,856,000. However, at issue was the appropriate imputation of the Sheboygan Falls off-balance sheet obligation into the financial capital structure. WP&L and Commission staff had imputed the obligation as debt, while WIEG had argued that since Sheboygan Power LLC is a WP&L affiliate, S&P would treat the affiliated lease as part of a consolidated credit profile and as a result it is appropriate to impute the lease obligation as 50 percent debt and 50 percent equity. The Commission is not persuaded that the lease would be treated differently than other leases and consequently a reasonable estimate of the debt-equivalent for the Sheboygan Falls lease is $141,856,000.

Also at issue was the appropriate methodology to calculate the debt-equivalent associated with the KNPP purchased power agreement. In its filing, WP&L applied a 40 percent factor to the present value of the capital cost recovery payments. WIEG questioned the use of the

40 percent factor. A review of WP&L's testimony in the KNPP sales proceedings, docket 05-EI-136, found that in that proceeding WP&L based its debt-equivalent on a 30 percent factor and capital cost recovery payments only. Subsequently, WP&L represented that the methodology that would be used by S&P had changed. While S&P would use the 40 percent factor, the calculation of the present value to which it would be applied would include additional minimum fixed payment streams. The Commission is not persuaded to use the later methodology because its support is a secondhand e-mail. Consequently, a reasonable estimate of the amount of debt-equivalents to be imputed into WP&L's financial capital structure is $41,746,000.

The aggregate amount of off-balance sheet debt-equivalents to be imputed into WP&L's financial capital structure is $347,750,000. This amount represents $30,470,000 of debt-equivalents associated with synthetic leases and existing operating leases, $133,679,000 associated with existing purchased power agreements, $41,746,000 associated with the KNPP purchased power agreement, and $141,856,000 associated with the Sheboygan Falls lease. The Commission will continue to review appropriate adjustments to the financial capital structure to reflect the impact of off-balance sheet obligations, and may consider other adjustment factors in future rate cases.

WIEG proposed that in its next rate proceeding WP&L be required to provide additional detailed information so that the parties can more accurately determine WP&L's off-balance sheet debt-equivalents and relative impacts on WP&L's financial capital structure. Specifically, WIEG recommended that the Commission direct WP&L to thoroughly evaluate and provide proof from S&P of what the debt equivalent factors will be used in S&P's credit rating process. The Commission is concerned that the record in this docket does not adequately support the alternatives provided and the issues in the case are too important to determine based on reading secondhand information. Consequently, it is reasonable that WP&L submit in its next case application detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent. The information shall include, at minimum, the minimum annual lease and purchased power agreement obligations; the method of calculation along with the calculated amount of the debt equivalent; and supporting documentation, including all reports, correspondence and any other justification that clearly established S&P's determination of the off-balance sheet debt equivalent, to the extent available, and publicly available documentation when S&P documentation is not available.

Incorporating the above off-balance sheet debt equivalents and other Commission determinations, WP&L's financial capital structure for the test year consists of 53.14 percent common equity, 3.02 percent preferred stock, 21.17 percent long-term debt, 4.38 percent short-term debt, 17.48 percent debt-equivalents of off-balance sheet obligations, and 0.81 percent advances from associated companies. The 53.14 percent common equity, on a financial basis, is within the common equity guideline of 47.5 to 54.0 percent.

Assessing the reasonableness of WP&L's capital structure depends upon three important principles. First, capital structure decisions must be based on WP&L's needs, not on the needs of the nonutility operations of the holding company. Second, the capital structure should provide adequate flexibility to WP&L and to the Commission to allow proper utility investment now and in the future. Third, the dividend policy of WP&L should be similar to typical electric and natural gas dividend practices as long as WP&L is below the estimated test year common equity ratio.

Generally, under Wis. Stat. § 196.795, the utility's capital needs must take precedence over nonutility needs if ratepayers are to be protected. The identification of utility needs goes beyond foreseeable needs. WP&L must have flexibility to finance both foreseen and unforeseen capital requirements.

In previous dockets the Commission recognized the need to protect ratepayers and to ensure that utility needs are placed before nonutility needs in capital structure and dividend policy choices. Consequently, WP&L may not pay dividends, including pass-through of subsidiary dividends, in excess of $92,264,000 if its actual average common equity ratio, on a financial basis, is or will fall below the test year authorized level, 53.14 percent.

The determination of whether the payment of dividends, over and above a typical or normal dividend, is appropriate can only be made at the end of the test year. Therefore, the applicant should wait until the end of the test year to pay additional dividends to the parent. Such dividends shall only be paid if their payment will not cause the common equity ratio, on a financial basis, to fall below the test year authorized level.

Ten-Year Financial Forecast

WP&L's ten-year financial forecast is useful to the Commission and should be submitted in future rate cases. WP&L's forecast should include both regulatory and financial capital structures and contain both the amount and percentage of the various capital components. The ten-year forecast can be combined with other business risk information to assess capital structure needs and rate of return requirements.

Regulatory Capital Structure and Cost of Capital

As in the previous rate case docket, Commission staff deducted WP&L's investment in common equity of American Transmission Company (ATC) net of deferred income taxes associated with transmission assets transferred to the ATC, along with other non-utility items, from its financial common equity to arrive at the common equity amount for its regulatory capital structure.

One issue arose regarding the netting of deferred income taxes associated with the transmission assets transferred to ATC. WIEG argued that the adjustment is inappropriate because deferred taxes are not included in the capital structure and therefore are not properly used to reduce the amount of WP&L's equity investment. However, the deferred income tax balance was not part of the actual transfer because ATC is a partnership and by itself is not an entity that pays income taxes. Each equity owner must report their share of ATC pretax earnings as part of their taxable income and ATC used the deferred tax balance as an offset to rate base in determining its rates to charge users of the transmission facilities. The Commission will continue to net the deferred income taxes from the ATC investment. In addition, the Commission will continue to exclude Advances from Affiliates from the regulatory capital structure.

A reasonable utility rate making capital structure for the purpose of establishing just and reasonable rates for the test year consists of 61.75 percent common equity, 4.04 percent preferred stock, 28.34 percent long-term debt, and 5.87 percent short-term debt. These values are calculated from the Commission staff's capital structure, by adjusting for the decisions in this proceeding.

Short-Term Debt

WP&L's test year capital structure contains approximately $87,143,000 of short-term debt. The interest rate associated with the short-term indebtedness is the commercial paper rate. A reasonable estimate of the average cost of short-term commercial paper for WP&L for the test year is 3.90 percent. This forecast is based on the average of test year commercial paper rate estimates provided by the Blue Chip Financial Forecasts newsletter. This is a reasonable and objective method of determining WP&L's short-term debt costs.

Long-Term Debt

WP&L's test year long-term debt includes an issuance of $100 million 30-year debt forecasted for mid-2006. A reasonable estimate for the cost of the indebtedness is 5.65 percent. WP&L's long-term debt also includes $55,100,000 of variable rate demand bonds. These tax-exempt bonds have an interest rate of approximately 65 percent of the commercial paper rate. Based on a commercial paper rate of 3.90 percent, a reasonable estimate of the average cost of the demand notes for WP&L for the test year is 2.55 percent. The resulting embedded cost of long-term debt of 6.55 percent is reasonable for the test year.

Preferred Stock

The average cost of preferred stock of 5.52 percent is reasonable for the test year.

Return on Equity

The principal factor used to determine the appropriate return on equity is the investors' required return. Authorized returns less than the investors' required return would fail to compensate capital providers for the risks they face when providing funds to the utility. Such sub-par returns would make it difficult for a utility to raise capital on an ongoing basis. On the other hand, authorized returns that exceed the investors' required return would provide windfalls to utility investors as they would receive returns that are in excess of the necessary level. Such high returns would be unfair to utility consumers who ultimately are responsible for paying for those returns.

If the investors' required return could be measured precisely, setting the authorized return on equity would be straightforward. Because that return cannot be measured precisely, determining the appropriate return on equity is typically one of the most contested issues in a rate proceeding. In this proceeding the applicant proposes that its authorized return remain at the 12.00 percent level approved in the prior proceeding. WIEG recommended that the return on equity be set no higher than 11.00 percent. The Commission staff suggested that the appropriate return on equity be set somewhere in the range from 10.00 to 11.50 percent.

In reaching its determination as to the appropriate return on equity, the Commission must balance the needs of investors with the needs of consumers. That balance is struck most reasonably in this proceeding by authorizing a return on equity equal to 11.50 percent. An 11.50 percent return should allow the applicant to attract capital at reasonable terms without unduly burdening consumers with excessive financing costs.

Using an 11.50 percent return on equity, the average utility capitalization ratios, annual cost rates, and the composite cost of capital rate considered reasonable and just for setting rates for the test year are as follows:

	Amount (000's)	Percent	Annual Cost Rate	Weighted Cost
Utility Common Equity	$ 917,203	61.75%	11.50%	7.10%
Preferred Stock	59,963	4.04%	5.52%	0.22%
Long-Term Debt	421,023	28.34%	6.55%	1.86%
Short-Term Debt	87,143	5.87%	3.90%	0.23%
Total Utility Capital	$1,485,332	100.00%		9.41%

The weighted cost of capital of 9.41 percent is reasonable for WP&L for the test year. It generates an economic cost of capital of 14.32 percent and a pre-tax interest coverage ratio of

6.85 times, on the regulatory capital structure, and 4.56 times, on the test year financial capital structure.

Construction Work in Progress

WP&L requested a current return on 50 percent of forecasted electric and natural gas CWIP in this case. Given WP&L's financial health, the adequacy of its cash flow, its quality of earnings, and the level of test-year construction expenditures, it is reasonable to allow a current return on 50 percent of electric and natural gas CWIP for the test year. The average CWIP that does not earn a current return will accrue AFUDC at the adjusted weighted cost of capital of 9.41 percent.

Rate of return on rate base

It is necessary that the 9.41 percent composite cost of capital be translated into a rate of return which can be applied to average net investment rate base and used to compute the overall return requirement in dollars.

The estimate of the WP&L's average net investment rate base plus CWIP for the test year is 94.96 percent of capital applicable primarily to utility operations plus deferred investment tax credit. This estimate reflects all appropriate Commission adjustments, and is a reasonable and just factor for use in translating the composite cost of capital into a return requirement applicable to average net investment rate base.

To allow a return on 50 percent of electric and natural gas CWIP, an adjustment must be added to the return on net investment rate base for the test year. Accordingly, the reasonable and just rates of return on Wisconsin retail electric and natural gas net investment rate bases for ratemaking purposes in this proceeding, computed on the basis of the above findings, are as follows:

	Retail Electric (%)	Retail Natural Gas (%)
Cost of Capital	9.41	9.41
Average Percent of Utility Net Investment Rate Base Plus Construction Work in Progress to Capital Applicable Primarily to Utility Operations Plus Deferred Investment Tax Credit	94.96	94.96
Percent Return Requirement Applicable to Net Investment Rate Base	9.91	9.91
Adjustment to Return Requirement to Provide Current Return on CWIP	0.30	0.17
Adjusted Percent Return Requirement on Net Investment Rate Base	10.21	10.08

Revenue Requirement

On the basis of the findings in this order, an $18,641,000 increase in Wisconsin retail electric revenues, and a $2,035,000 increase in Wisconsin natural gas revenues are reasonable. The indicated rate revisions are computed as follows:

	Retail Electric (000's)	Retail Natural Gas (000's)
Return Earned on Average Net Investment Rate Base at Present Rates	9.05%	9.39%
Required Return on Average Net Investment Rate Base	10.21%	10.08%
Earnings Deficiency as a Percent of Average Net Investment Rate Base	1.16%	0.69%
Average Net Investment Rate Base (000's)	$964,028	$175,770
Amount of Earnings Deficiency on Average Net Investment Rate Base (000's)	$11,160	$1,218
Revenue Deficiency to Provide for Earnings Deficiency Plus Federal and State Income Taxes at a Combined Rate of 40.135 percent (000's)	$18,641	$2,035

Prudence Issue

In docket 6680-CE-168 (the Sheboygan Falls Facility or SFF docket, order mailed May 18, 2005), Commission staff indicated that a coal-fired power plant by 2008 could have been up to $84 million less expensive than the company's proposal (which included the SFF). In its discussion of the SFF docket, the Commissioners approved the SFF, but with a reduction in the cost of the project and a reduction in the rate of return to be incorporated. The Commission stated that the proper venue for a prudence argument was in a rate case, not a construction case.

WP&L raised several arguments against the proposed prudence adjustment. First, WP&L stated that "Least cost is only one criterion when considering adding generating assets and cites the Commission's brief to the Wisconsin Supreme Court in *Clean Wisconsin, Inc. v. PSC* in support of its argument. WP&L also cited the impact of the Midwest Independent System Operator's (MISO) limited firm transmission capabilities and the MISO Day 2 market on the overall "cost" associated with the various generating options.

Second, WP&L stated that it "did not acknowledge a need for baseload capacity by 2006. In reports to the SEC, WP&L stated on several occasions that they would construct 500 MW of coal-fired generation by 2006. However, WP&L testified that construction of a baseload plant in the 2006-2008 time period was based on choice, not need. WP&L's choice to add baseload generation was dependent on assurance from the Commission that the Power the Future (PTF) model would be accepted for the Wisconsin Energy Corporation (WEC) plants and extended to other state utility holding companies (such as WP&L).

Third, WP&L stated that the addition of a baseload plant in 2008 would not result in an $84 million savings over the SFF. The company stated that installing a coal facility by 2008 would not eliminate the need for the SFF.

Based on the information provided in this docket and the Commission's decision in docket 6680-CE-168, it is not reasonable to assess a prudence penalty against WP&L's revenue requirement in this proceeding.

Gas Cost Recovery Mechanism

WP&L has an incentive GCRM. As such, the company shares in a portion of the savings or excess costs it realizes beyond a benchmark cost of gas. The record in this case, however, indicates that WPL had the highest total cost per therm in four of the last six years, and that in three of the years in which it had the highest costs, its shareholders also received incentive profits. Based on this finding, the Commission finds it reasonable to modify WP&L's GCRM as follows:

- The reliability premium adder, which is designed to cover the costs of reliability premiums, shall be reduced from 2.5 percent to 1.4 percent.
- Treatment for stored gas shall be modified so that it is more in line with the practices of other utilities. WP&L shall work with Commission staff to achieve this modification, and approval of the final design is delegated to the Gas and Energy Division Administrator.
- The fixed costs associated with LS Power shall be eliminated from the Pipeline Fixed Cost Adder.
- The variable costs associated with LS Power shall be eliminated from the Miscellaneous Cost Adder.
- The costs associated with Progas and Pan Alberta shall be eliminated from the Miscellaneous Cost Adder.
- The pipeline and storage variable cost portion of the Miscellaneous Cost Adder shall be reduced from $.0.052/dth to $0.047/dth.
- The No-notice overrun cost portion of the Miscellaneous Cost Adder shall be reduced from $0.004 to $0.0016.

Demand-Side Management (DSM)

Shareholder return for Shared Savings investments

Prior to 2004, WP&L received the same return, its weighted cost of capital (WCOC), on its Shared Savings investments as it did for other investments. In docket 6680-UR-113, the Commission determined the risk for Shared Savings investments to be less than that of utility generation investments. The Commission further determined that an appropriate return for Shared Savings investments is a WCOC that reflects an 8 percent return on equity. In this proceeding, WP&L requested that its allowed return on its Shared Savings investments be restored to the level that it receives on other capital investments.

WP&L had provided electric and natural gas energy efficiency services to commercial and industrial customers through its Shared Savings Program since 1987. It is evident that WP&L's Shared Savings Program provides energy and demand savings benefits. The Commission recognizes that Shared Savings investments may have lower risk than other capital investments. However, this reduced risk can be reflected in the determination of the allowed return on equity. It is therefore appropriate for WP&L to receive the same level of return on Shared Savings investments as it does on other investments. Providing this level of return for Shared Savings investments also encourages WP&L to continue to aggressively pursue the achievement of energy efficiency through its Shared Savings Program.

Level of free-riders in the Shared Savings Program

Order Point 20 of the Commission's order in docket 6680-UR-112 required WP&L to make changes to its Shared Savings Program to reduce program free-rider levels. WP&L implemented program modifications on August 1, 2003. In docket 6680-UR-113, the Commission required WP&L to closely monitor the impact on participation resulting from the modifications made to the Shared Savings Program. WP&L's Shared Savings Program is a significant part of its resource plan. From 1997 through 2003, the program has saved an average of about 12 MW annually. Because of the magnitude of the Shared Savings Program, in terms of savings and cost, it is important that the program be designed as cost-effectively as possible. It is therefore appropriate for WP&L to closely monitor how modifications to its Shared Savings Program have impacted program participation and to analyze program participation data to provide insight regarding changes in the level of free-riders. WP&L shall report on the level of free-riders in the Shared Savings Program in the next rate proceeding.

True-up Mechanism and performance-base incentives

The reduced level of energy efficiency savings achieved in Wisconsin in the last few years may indicate a need for mechanisms to encourage additional energy efficiency procurement. Two possible mechanisms were presented in this proceeding. A true-up mechanism would decouple sales from profits and remove a disincentive for the implementation of aggressive energy efficiency programs. Performance-based incentives reward a utility for energy efficiency achievement. To the extent that the Commission-approved return for Shared Savings investments is higher than the risk-adjusted return required by shareholders, WP&L receives an incentive. However, any incentive WP&L currently receives is not performance-based as the return is received on every dollar spent on Shared Savings investments regardless of the acquisition of any energy efficiency savings. While the time is right to fully explore true-up mechanisms and performance-based incentives, this proceeding is not the appropriate venue.

Electric and natural gas escrow budget levels

The appropriate conservation escrow budget to include in revenue requirement is $28,977,752, with $23,586,943 allocated to electric and $5,390,809 allocated to natural gas operations. This adjusts WP&L's proposed budget by $3,041,449 (electric) to remove direct load control dollars reclassified to non-escrowed expense and $168,000 ($122,000 electric and $46,000 natural gas) for Commission staff's advertising adjustment.

Energy efficiency goals and measures of success

WP&L did not propose energy savings goals or measures of success for its energy efficiency services for the 2005-2006 test year. These services include customer service conservation activities, load management activities, and the Shared Savings Program. It is reasonable for WP&L to work with Commission staff to develop measures of success and savings goals for its 2005-2006 energy efficiency services. The measures of success and savings goals should reflect the Commission's decisions regarding the Shared Savings Program. Measures of success and savings goals should be provided to Commission staff by October 17, 2005. WP&L currently has no measures of success or savings goals for its load management activities. All utilities, including WP&L should be aggressively pursuing load management options, particularly for their smaller customers. It is appropriate that the measures of success and savings goals provided to Commission staff address WP&L's load management efforts.

Electric COSS

WP&L, other parties, and Commission staff gave testimony as to what COSS should be considered for the allocation of electric costs in this docket. Several different, defendable types of COSS were presented that constitute a "range of reasonableness" for purposes of rendering a decision on revenue allocation. It is therefore reasonable for the Commission to continue its policy of relying on several types of electric COSS, as well as other factors such as bill impacts and comparisons, rate design, and marginal energy costs when allocating revenue responsibility. This has been the Commission's policy in the past and it continues to be the appropriate policy.

Commission Meyer noted that there is no one perfect way to allocate costs and stated a preference for certain positions relating to allocation issues; but both Chairperson Ebert and Commissioner Meyer do not want to limit the Commission to the consideration of a single COSS. Commissioner Meyer's COSS allocation statements included a preference for the allocation of production plant using both energy and demand allocators, but believes that the precise split is debatable; that is not reasonable to exclude interruptible demand from the demand allocator because double counting of the interruptible credit may result; and that the use of only firm demand to allocate common costs skews the results of a COSS.

COSS Collaborative

A proposal was made by the applicant and WIEG for the Commission to direct parties to work with Commission staff in a collaborative effort on COSS issues. The Commission agrees that it is critical that cost causation information needs to be included in the Commission's deliberations. The Commission appreciates the parties proposal to review COSS issues. As a first step to opening up a meaningful discussion on COSS, the Commission directed its staff to circulate for comment its cost-of-service study report for comment by interested persons. Chairperson Ebert urged that all parties use this review opportunity to constructively narrow the divergent views on COSS. Commissioner Meyer agreed with this approach.

Identification of Peak-Hour Demand Drivers

During testimony, CUB argued that WP&L has overstated the coincident peak demand of its General Service, Gs-1, tariff class which consists of small energy use customers. WP&L disputed this assertion. Because the coincident peak demand allocator is such a significant allocator in the allocations of WP&L costs, it is reasonable to require WP&L to identify the peak-hours drivers for capacity during non-summer months and submit this information in its next rate case.

Tracking of Load-Management, Conservation, and Shared Savings Program Costs

The costs and expenditures associated with load management, conservation, and Shared Savings programs are not currently kept track of on the basis of the rate tariff class that a customer participating in the program belongs to. It is difficult to properly assign costs to classes without tracking and forecasting expenditures using a customer's electric rate tariff. It is reasonable to direct WP&L to track and forecast load management, conservation, and Shared Savings program expenditures by the electric rate tariff class of the customer.

Expansion of Net Energy Metering and Establishment of a Special Buyback Rate for Wind Generators

When the Commission established buyback rates for customer-owned generation in 1982, it decided to allow net energy metering for generators with a maximum output of 20 kW or less. The Commission determined that the small size of such generators and the small amount of excess electricity available for sale from such small generators did not justify the costs of a second meter that would be necessary to measure the electricity that might flow onto the utility's distribution system. In the late 1980s, the Commission restricted the availability of net energy metering to renewable generators.

Under net energy metering, the customer's meter is allowed to run in reverse when the output of the customer's generator exceeds the customer's load and energy is flowing from the customer's premises onto the utility distribution system. Net energy metering allows the customer to "bank" electric energy and withdraw kWhs from the utility at a later time. If the customer on net uses fewer kWhs than the output of the generator, the utility will pay the customer for the excess kWhs at the retail rate or allow the net kWhs to be used during a succeeding month. The effect of net energy metering is that the customer receives the retail rate for all kWhs that the generator produces.

Net energy metering is currently available to customers that own generators with a maximum output of 20 kW or less. In this proceeding, RENEW Wisconsin (RENEW) proposed that the Commission expand the availability of net energy metering to customers with generators that have a capacity of 100 kW or less.

RENEW stated that the 20 kW limitation on net energy billing was established more than 20 years ago and was now outdated because of new wind turbine technology and greater electric consumption by customers. RENEW argued that the availability of net energy metering was a significant incentive for the owners of existing renewable generators and that expanding the availability of net energy billing would create an incentive for the installation of additional renewable energy systems.

WP&L testified that net energy metering is based on the premise that it is too costly to install separate meters for small generators. WP&L argued that the retail kWh rates include the costs of production, transmission, distribution and other infrastructure and that the sum of these costs exceed the utility’s avoided costs Therefore, WP&L concluded that expanding the availability of net energy metering will result in a subsidy from other customers.

WP&L’s electric rate structure provides that customers with demands greater than 75 kW are billed under rate schedules with demand charges. The demand charge portion of the customer’s bill is assessed against the customer’s maximum 15 minute demand during the month. RENEW contends that demand charges act as a barrier to the installation of wind generators because it is not possible for the customer to offset demand charges with wind generators. In order to eliminate this barrier, RENEW proposed to implement a special wind energy buyback rate for customers that install wind generators with capacities between 100 kW and 660 kW. RENEW recommended that the special buyback rate be set at the level of the Gs-1 retail rate schedule. RENEW's proposal would effectively expand the availability of net energy billing for all wind generators with a capacity of 660 kW or less. RENEW argued that providing a special energy-only buyback rate for demand metered customers would improve the economics of wind generation.

WP&L opposed the special wind energy buyback rate because it believes such a rate would result in a subsidy from other customers and that such incentives are already being paid from the public benefits fund.

The Commission is not convinced at this time that it would be appropriate to expand the availability of net energy metering, or to implement a special buyback rate for wind generators. However, it has been over 20 years since the current method of determining buyback rates was developed. The Commission believes it would be appropriate for WP&L to work with the Commission staff to analyze the standard buyback rate and propose possible revisions.

Compatibility of Air Conditioning Direct Load Control with the MISO Day 2 Market

WP&L has a direct load control program under which it has the capability to control residential air conditioners during periods of high demand. Credits are paid to customers only in the event the control system is utilized. WP&L is also analyzing a new system in which the utility controls customer air conditioners with a control on the customer's thermostat.

It is not clear at this time how these direct load control systems will be used in conjunction with the MISO Day 2 energy market. The Commission finds that it would be reasonable for WP&L to submit a report to the Commission by January 1, 2006, which provides an analysis of the compatibility of its existing direct load control system and the controlled thermostat direct load control system with the MISO Day 2 energy market. Such a report should include proposals for any possible changes to these programs to make them compatible with the MISO Day 2 energy market.

Electric Revenue Allocation and Rate Design

Based upon the conflicting results from the COSS information in the record and the small overall electric increase after consideration of the recent interim fuel increase, the Commission determined that the electric revenue increase be allocated relatively uniform with a slightly lower than average increase for the Cp-2 customer class and a slightly higher than average increase for all of the other customer classes.

The Commission approved the Commission staff's electric rate design as adjusted for the final revenue requirement. In addition the Commission approved an experimental rate provision for the Cp-2 customer class, called a Load Factor Energy Credit. This provision provides an energy credit for customers that use large amounts of energy around the clock. This is a pilot program. This Energy Credit will be reviewed in WP&L's next rate case to see if it is achieving the intended benefits. The Commission determined that interruptible credits should be left unchanged. The Commission determined that parallel generation rates should be increased, to reflect increased marginal energy costs. The authorized revenue allocation and rate design for electric utility service is shown in Appendix B.

Natural Gas Master Meter Operators

Natural Gas Master Meter Operators pose a unique challenge to the state for achieving natural gas safety compliance. The Commission staff has been working with the state's natural gas utilities to identify these customers and to develop means of addressing the safety concerns.

WP&L proposed to work with Commission staff to identify master meter operators in its service territory, to offer them a six-month waiver of the company's extension rules costs, and to add tariff language the would address the future creation of mater meter operators, including the notification of the Commission and the requirement for initial compliance with state and federal pipeline safety codes to receive service.

Commission staff supported WP&L's proposal but sought to add the requirement that the company provide federally-mandated inspection and survey services, at a fee, to those customers who chose to retain their master meter systems because of concerns regarding monthly meter charges, etc. Commission staff was concerned that the system operators do not meet federal requirements for working on natural gas systems and that these services are not readily available to them through third parties and that failure to require the company to provide the services could leave an on-going safety concern.

WP&L testified that requiring the company to provide these services was outside of the Commission's authority. They also noted that requiring the company to provide these services on systems that they do not operate or control would expose them to uncompensated liability in the instance of an explosion or other incident. They testified that the increased monthly costs associated with the customer service charge should not be an impediment to the customer moving from a master meter system to individually metered facilities.

The Commission adopted WP&L's proposal and, based on the concerns regarding increased liability that would be taken on by the company, would not require that they provide inspection or other survey services on a fee-for-service basis.

Natural Gas COSS

Three studies were performed to determine how the costs of providing natural gas distribution service could be fairly apportioned among the customer classes. WP&L performed one embedded COSS, while Commission staff performed two embedded COSS.

The COSS utilize different methods to allocate costs to the customer classes. The allocation method of the greatest individual importance is the method used to allocate costs related to distribution mains, which comprise the majority of the costs associated with providing natural gas distribution service. The WP&L COSS allocates mains-related costs to the customer classes based on a combination of customer number, average usage and peak demand. Commission staff's COSS A uses a methodology similar to the WP&L COSS. Commission staff's COSS B utilizes a combination of average usage and peak demand.

The participants expressed differing opinions about the reasonableness of the various methods used to allocate mains-related costs. The Commission has not endorsed a particular COSS methodology in the past and has relied on the results of all of the COSS to provide a range of reasonableness for revenue allocation and rate design. This continues to be an appropriate policy.

Rate Design

In prior rate case docket 6680-UR-112, the Commission determined that interruptible distribution service customers essentially receive firm service and ordered that discounted interruptible distribution rates be phased out. The last step in phasing out these rates is completed in this docket. To accomplish this, WP&L's three firm commercial classes are merged with its four interruptible commercial classes to form six new firm distribution classes based on customer usage levels.

Additionally, WP&L's larger generators are transferred to two new firm distribution generation classes, due to their unique load characteristics. System supply customers with usage greater than 20,000 therms annually which are included in the new commercial and generation classes can elect to receive interruptible gas supply.

The new class structure is shown below:

Authorized Customer Class	Authorized Class Usage Requirement (Therms)	Present Customer Class
Gc-1 Small Comm.	<= 5,000	Gc-1 Small Firm
Gc-2 Comm. & Ind.	>5,000 and <=20,000	Gc-2 Medium Firm <=20,000
Gc-3 Comm. & Ind.	>20,000 and <=200,000	Gc-2 Medium Firm >20,000 Ig-1 Small Interruptible
Gc-4 Comm. & Ind.	>200,000 and <=1.3 million	Gc-3 Large Firm Ig-2 Medium Interruptible
Gc-5 Comm. & Ind.	>1.3 million and <= 7.5 million	Ig-3 Large Interruptible
Gc-6 Comm. & Ind.	>7.5 million	Ig-4 SuperLarge Interruptible
GN-9 Small Generation	>200,000 and <=7.5 million	Ig-2 Medium Interruptible Ig-3 Large Interruptible
GN-10 Large Generation	>7.5 million	Ig-4 SuperLarge Interruptible

Appendix C shows the rate design approved by the Commission. The authorized rate design minimizes customer bill impacts and provides for smooth bill transitions when customers are transferred between the commercial classes based on decreased or increased usage.

Tariff Changes Due to the New Distribution Service Customer Classes

Due to the merging of firm and interruptible commercial classes and the creation of two generation classes, the following tariff changes are necessary:

- References to the present customer classes throughout the tariffs are changed to reflect the new customer classes.

- Four transportation service riders are consolidated into one schedule, the T-1 Transportation Service Rider. This schedule provides transporters with firm distribution service, with or without back-up service for a portion of their load.
- The curtailment plan is changed to reflect the appropriate priority of service resulting from these changes.

Lost and Unaccounted for Gas Factor

It is reasonable to credit or charge all customers for gas gains or losses to adjust for variations in the amount of gas delivered to WP&L's system and the amount of usage metered. A Lost and Unaccounted for Gas Factor of 0.85 is established. The factor is based on the historic three-year average of losses to total throughput for the WP&L gas system.

Base Gas Pressure

WP&L has been replacing regulators with 6" water column pressure with regulators with 7" water column pressure, as necessary, to allow for more efficient operation of modern appliances. The company anticipates complete replacement in seven to ten years.

To reflect this new standard, the tariff base gas pressure is changed from 6" of water column above the atmospheric pressure to 7" of water column above the atmospheric pressure. The billing factor of 6" base pressure will continue to be applied to metered usage until over one-half of the customers have natural gas metered at 7" water column.

WorryProof Bill [WPB] Program

The WPB program offers residential and commercial customers the option to lock into a fixed monthly bill for twelve months that does not vary based on usage, weather or the price of natural gas. The fixed bill amount is based on the customer's weather-normalized historical usage. The company hedges natural gas supply to serve program participants. The participants are billed for the hedged gas supply, along with the applicable distribution charges and an administrative fee. The administrative fee collects program expenses such as the costs of calculating fixed bill amounts for potential customers and marketing.

Numerous changes were proposed regarding the WPB program:

- WP&L proposed to include an estimate of anticipated distribution rate increases in the bills of WPB program participants, because it cannot incorporate increases generally effective in January into fixed bills entered into in the preceding November.
- Commission staff proposed that, if WP&L is allowed to include an estimate of anticipated distribution rate increases in bills, the current 7 percent administrative fee should be reduced to reflect a decrease in the risk of under-recovery of distribution revenues.
- CUB proposed eliminating the automatic re-enrollment of participants at the beginning of each program year, indicating this would cause customers to more carefully weigh whether re-enrolling in the program is worth its costs.
- CUB proposed that WP&L be required to automatically provide participants with the amount they would have paid under traditional rates in the previous year when a WPB amount is provided to for the upcoming year, indicating this information is necessary for participants to make an informed decision on whether to continue in the program.
- CUB proposed including customers with arrears balances in the program, believing it is discriminatory to not include them.
- Commission staff proposed that WP&L be required to account for the incremental costs and revenues of the program above-the-line rather than below-the-line, because the WPB program is a utility service offering.
- CUB proposed that any net revenues from the program be directed to ratepayers. Currently, net revenues or costs are directed to shareholders.
- CUB proposed that the Commission conduct a comprehensive review of the program prior to the November 2005 program year to address concerns it raised about its costs and benefits.

At this time, it is not appropriate to make any changes in the WPB program. The program is approved as a pilot program through October 2006. Commission staff will conduct a comprehensive review of the WPB program beginning in early 2006, after the final year of the pilot program is underway and before a decision is necessary as to whether WP&L should continue to offer the program.

Credit Card Payments of Natural Gas and Electric Bills

WP&L customers can pay their natural gas and electric bills by credit card via a third party vendor, which charges a fee for each payment. CUB believes there should be no charge for using credit cards, to encourage bill payment. Additionally, CUB believes this charge discriminates against customers who are threatened by disconnection, who may be more likely to use credit cards to pay their bills. CUB proposed including the costs of accepting credit card payments in rates.

The company indicates that it accepts credit card payments as a convenience to customers, and believes the costs associated with accepting these payments should be borne by the users. Accepting credit card payments without charge could add significant costs to rates.

It is appropriate that the costs associated with credit card payments are borne by the users. If the costs associated with credit card payments would be included in rates, the cost of service for all customers would increase to provide this payment option to a portion of customers. The company currently offers a number payment options without charge that can be utilized by customers who do not choose to pay their bill via check or money order.

WP&L is required to file a tariff outlining its credit card acceptance policies and associated fees. The tariff will contain a provision that the company will seek the most cost-effective means for customers to use their credit cards when its existing third party vendor contract expires. This will ensure that credit card payments are being processed using the vendor that is the best value for customers.

Commingling of overdue electric and natural gas bill amounts

CUB raised the issue of WP&L's commingling of overdue electric and natural gas bill amounts on customer bills and taking collection and disconnection action based on the entire amount overdue. They argued that this practice is unfair, that they are two separate utility services and that the customers should have the same rights as if they were served by separate utilities.

WP&L testified that it operates within the existing laws and rules and that its current practice is not prohibited by the applicable administrative code provisions.

Based on the evidence presented in this case, WP&L's practices are in compliance with the existing administrative rules and there is no basis to direct them to change their practices.

Order

1. This final decision shall be effective one day after the date of mailing. The authorized rates and rules shall also be effective on the same date, provided that the rates are filed with the Commission and placed in all offices and pay stations of the utility by that date. If the authorized rates and rules are not placed in all offices and pay stations by the effective date of the order, the rates shall become effective on the date that the rates are placed in all offices and pay stations. The applicant shall inform the Commission, in writing, of the date that the authorized rates and rules are to take effect.

2. WP&L shall prepare bill inserts that appropriately identify the rates authorized in the final decision. WP&L shall distribute the inserts to customers with the first billing containing these rates and shall file copies of these inserts with the Commission before it distributes the inserts to customers.

3. WP&L is authorized to revise its existing rates and rules for electric and natural gas service using the rate and rule changes authorized in this order and as shown in Appendices B and C.

4. The fuel costs in Appendix D shall be used for monthly monitoring of WP&L's fuel costs, pursuant to Wis. Admin. Code ch. PSC 116.

5. WP&L is authorized to continue to defer any cost incurred for invoking the Direct Load Control program until the next rate proceeding.

6. WP&L is authorized to continue escrowing the network transmission cost, the cost associated with firm point-to-point transmission wheeling charges, point-to-point transmission wheeling cost for the access to economy energy, and any FERC approved SECA charges until January 1, 2007, or the next base rate proceeding whichever is earlier. Transmission wheeling charges for access to economy energy may not be included in monitored fuel costs.

7. WP&L shall defer the difference between the fixed cost charges collected in revenue requirement for the Sheboygan Falls leased facility and the actual fixed lease payments resulting from the Commission decision in docket 6680-CE-168.

8. WP&L shall provide a detailed explanation of actual economic development activities in its next rate proceeding in accordance with the Opinion section.

9. WP&L shall defer the revenue requirement impacts of all recoveries and incremental costs associated with the potential settlement of a claim for damages filed by WPSC over a dispute for the storage of spent nuclear fuel with carrying costs at the authorized pre-tax weighted average cost of capital.

10. WP&L shall defer the revenue requirement impacts of the American Jobs Creation Act of 2004 until its next rate proceeding.

11. WP&L shall record annual DSM accrual amounts of $25,329,956 for Wisconsin retail electric operations ($22,864,363 of authorized escrowed expenditures, including

$8,342,576 for the return on share savings, $11,611,292 to the DOA to fund public benefits, $2,000,000 for farm rewiring programs, plus $2,465,593 for amortization of DSM overspending) and $6,680,272 for Wisconsin natural gas operations ($5,262,717 of authorized escrowed expenditures including $1,719,631 for the return on Shared Savings, $13,348,393 to the DOA to fund public benefits, plus an escrow adjustment of $1,417,555 for amortization of DSM overspending). Both amortizations shall begin with the effective date of this Final Decision. WP&L shall continue to record these amounts until the Commission authorizes new DSM accrual amounts.

12. WP&L shall record conservation escrow balances adjustments for disallowed advertising of $145,350 for electric operations and $25,650 for natural gas operations.

13. WP&L shall use a return on equity of 11.5 percent to provide the shareholder return for investments made through its Shared Savings Program.

14. WP&L shall work with Commission staff to modify its treatment for stored gas so that it is more in line with the practice of other utilities. Approval of the final design is delegated to the Gas and Energy Division Administrator.

15. The GCRM shall be modified as discussed in the Opinion.

16. WP&L shall submit a ten-year financial forecast in its next rate proceeding. The forecast shall contain both regulatory and financial capital structures and contain both the amount and percentage of the various capital components.

17. WP&L may not pay dividends, including pass-through of subsidiary dividends, in excess of $92,264,000 if its actual average common equity ratio, on a financial basis, is or will fall below the test year authorized level of 53.14 percent.

18. WP&L shall submit in its next case application detailed information regarding all off-balance sheet obligations for which the financial markets will calculate a debt equivalent. The information shall include, at minimum, the minimum annual lease and purchased power agreement obligations; the method of calculation along with the calculated amount of the debt equivalent; and supporting documentation, including all reports, correspondence and any other justification that clearly established S&P's determination of the off-balance sheet debt equivalent, to the extent available, and publicly available documentation when S&P documentation is not available.

19. WP&L shall closely monitor how modifications to its Shared Savings Program have impacted program participation and analyze program participation data to provide insight regarding changes in the level of free-riders. WP&L shall report on the level of free-riders in the Shared Savings Program in the next rate proceeding.

20. WP&L shall work with Commission staff to develop measures of success and savings goals for its 2005-2006 customer service conservation activities, load management activities, and Shared Savings Program. These measures of success and savings goals shall be filed with the Commission by October 17, 2005.

21. WP&L shall identify peak-hours drivers of capacity during non-summer months and to submit this information in its next full electric rate case.

22. WP&L shall track and forecast Load Management, Conservation, and Shared Savings program expenditures by customer rate tariff and to submit this information in its next full electric rate case.

23. WP&L shall work with the Commission staff to analyze the standard electric buyback rate and propose revisions.

24. WP&L shall file a report with the Commission within 90 days of the date of this order on it direct load control programs as discussed in the Findings of Fact.

25. WP&L shall file a tariff outlining its credit card acceptance policies and associated fees consistent with the Opinion discussion.

26. Jurisdiction is retained.

Dated at Madison, Wisconsin, July 19, 2005

By the Commission:

Christy L. Zehner

Christy L. Zehner
Secretary to the Commission

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See attached Notice of Appeal Rights

Notice of Appeal Rights

Notice is hereby given that a person aggrieved by the foregoing decision has the right to file a petition for judicial review as provided in Wis. Stat. § 227.53. The petition must be filed within 30 days after the date of mailing of this decision. That date is shown on the first page. If there is no date on the first page, the date of mailing is shown immediately above the signature line. The Public Service Commission of Wisconsin must be named as respondent in the petition for judicial review.

Notice is further given that, if the foregoing decision is an order following a proceeding which is a contested case as defined in Wis. Stat. § 227.01(3), a person aggrieved by the order has the further right to file one petition for rehearing as provided in Wis. Stat. § 227.49. The petition must be filed within 20 days of the date of mailing of this decision.

If this decision is an order after rehearing, a person aggrieved who wishes to appeal must seek judicial review rather than rehearing. A second petition for rehearing is not an option.

This general notice is for the purpose of ensuring compliance with Wis. Stat. § 227.48(2), and does not constitute a conclusion or admission that any particular party or person is necessarily aggrieved or that any particular decision or order is final or judicially reviewable.

Revised 9/28/98

APPENDIX A
(CONTESTED)

In order to comply with Wis. Stat. § 227.47, the following parties who appeared before the agency are considered parties for purposes of review under Wis. Stat. § 227.53.

Public Service Commission of Wisconsin
(Not a party but must be served)
610 N. Whitney Way
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WISCONSIN INDUSTRIAL ENERGY GROUP
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Steven Heinzen
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Madison, WI 53701-2719

WISCONSIN PAPER COUNCIL
Earl J. Gustafson
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Neenah, WI 54957-0718

WISCONSIN POWER & LIGHT COMPANY

SUMMARY OF ELECTRIC REVENUES
FOR TEST YEAR 2005/6

RATE CLASS	Schedule	PRESENT REVENUES	AUTHORIZED REVENUES	DOLLAR INCREASE	PERCENT INCREASE
General Service	Gs-1	$ 448,256,638	$ 458,545,636	$ 10,288,998	2.30%
General Service TOD	Gs-3	6,486,152	6,634,680	148,528	2.29%
General Service Non-metered	Gs-4	244,009	249,729	5,720	2.34%
General Service TOD w/ Water Heating	Gw-1	2,676,223	2,736,889	60,666	2.27%
Controlled Water Heating (17 hr.)	Rw-1	1,108,058	1,133,656	25,598	2.31%
Controlled Water Heating (11 hr.)	Rw-3	270,507	276,805	6,298	2.33%
Commercial Service - Standard	Cg-2	64,199,268	65,702,882	1,503,614	2.34%
Commercial Service - TOD	Cg-2 TOD	17,400,067	17,806,056	405,989	2.33%
Industrial Service - Secondary/Primary	Cp-1	214,863,596	219,762,357	4,898,761	2.28%
Industrial Service - Transmission	Cp-2	64,640,501	65,879,576	1,239,075	1.92%
Industrial Service - Transmission	Cp-2 HLF	11,030,678	10,925,236	(105,442)	-0.96%
Streetlighting Service	Ms-1	4,776,007	4,889,681	113,674	2.38%
Decorative Lighting	Ms-2	41,399	42,329	930	2.25%
Area Lighting	Ms-3	1,767,227	1,808,122	40,895	2.31%
Traffic Signal Lighting	Mz-1	315,889	323,432	7,543	2.39%
Civil Defense & Fire Sirens Service	Mz-2	6,428	6,574	146	2.27%
Non-Standard Lighting	NL-1	48,798	48,809	11	0.02%
TOTAL ELECTRIC		**$ 838,131,445**	**$ 856,772,449**	**$ 18,641,004**	**2.22%**

WISCONSIN POWER & LIGHT COMPANY

SUMMARY OF ELECTRIC RATES

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	AUTHORIZED RATES

GENERAL SERVICE, Gs-1

Equivalent Monthly Customer Charge:	Single-phase	$7.00	$7.40
	Three-phase	$15.01	$15.00
Daily Customer Charge:	Single-phase	$0.2301	$0.2433
	Three-phase	$0.4936	$0.4932
Energy Charge (per kWh):	Summer	9.3520 ¢	9.9160 ¢
	Non-Summer	8.4320 ¢	8.9500 ¢
Primary Voltage Discount		2.50%	2.50%
Fuel Adjustment Clause (per kWh)		0.3521 ¢	0.0000 ¢

GENERAL SERVICE TIME-OF-DAY, Gs-3

Equivalent Monthly Customer Charge:	Single-phase	$7.75	$7.40
	Three-phase	$16.00	$15.00
Daily Customer Charge:	Single-phase	$0.2548	$0.2433
	Three-phase	$0.5260	$0.4932
Energy Charge (per kWh):			
On-Peak (12 hr.):	Summer	16.0170 ¢	17.1700 ¢
	Non-Summer	15.1070 ¢	16.2030 ¢
Off-Peak (12 hr.):	Summer	3.9970 ¢	4.1400 ¢
	Non-Summer	3.9970 ¢	4.1400 ¢
On-Peak (14 hr.):	Summer	15.5180 ¢	16.5100 ¢
	Non-Summer	14.5980 ¢	15.5800 ¢
Off-Peak (10 hr.):	Summer	3.8540 ¢	4.1400 ¢
	Non-Summer	3.8540 ¢	4.1400 ¢
Primary Voltage Discount		2.50%	2.50%
Fuel Adjustment Clause (per kWh)	On-Peak (12 hr.):	0.8895 ¢	0.0000 ¢
	Off-Peak (12 hr.):	(0.0071) ¢	0.0000 ¢
	On-Peak (14 hr.):	0.7625 ¢	0.0000 ¢
	Off-Peak (10 hr.):	(0.0076) ¢	0.0000 ¢

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	AUTHORIZED RATES

GENERAL SERVICE NON-METERED, Gs-4

Equivalent Monthly Customer Charge		$5.25	$5.50
Daily Customer Charge		$0.1726	$0.1808
Energy Charge (per kWh)	Summer	9.1540 ¢	9.6690 ¢
	Non-Summer	8.2350 ¢	8.6600 ¢
Fuel Adjustment Clause (per kWh)		0.3081 ¢	0.0000 ¢

CONTROLLED WATER HEATING 17 HR. SERVICE, Rw-1

Equivalent Monthly Customer Charge		$3.10	$3.30
Daily Customer Charge		$0.1019	$0.1085
Energy Charge (per kWh):	Summer	8.2640 ¢	8.6160 ¢
	Non-Summer	7.7540 ¢	8.0800 ¢
Fuel Adjustment Clause (per kWh)		0.2157 ¢	0.0000 ¢

CONTROLLED WATER HEATING 11 HR. SERVICE, Rw-3

Equivalent Monthly Customer Charge		$3.10	$3.30
Daily Customer Charge		$0.1019	$0.1085
Energy Charge (per kWh)	Summer	5.7250 ¢	5.8070 ¢
	Non-Summer	5.2060 ¢	5.2800 ¢
Fuel Adjustment Clause (per kWh)		0.0155 ¢	0.0000 ¢

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	AUTHORIZED RATES

GENERAL SERVICE TIME-OF-DAY with WATER HEATING, Gw-1

Equivalent Monthly Customer Charge		$7.75	$7.40
Daily Customer Charge		$0.2548	$0.2433
Energy Charge (per kWh):			
On-Peak (12 hr.):	Summer	15.2190 ¢	16.0890 ¢
	Non-Summer	14.3100 ¢	15.1110 ¢
Off-Peak (12 hr.):	Summer	3.8000 ¢	3.9100 ¢
	Non-Summer	3.8000 ¢	3.9100 ¢
On-Peak (14 hr.):	Summer	14.4640 ¢	15.4700 ¢
	Non-Summer	13.5500 ¢	14.5300 ¢
Off-Peak (10 hr.):	Summer	3.6380 ¢	3.9100 ¢
	Non-Summer	3.6380 ¢	3.9100 ¢
Fuel Adjustment Clause (per kWh)	On-Peak (12 hr.):	0.8464 ¢	0.0000 ¢
	Off-Peak (12 hr.):	(0.0104) ¢	0.0000 ¢
	On-Peak (14 hr.):	0.7625 ¢	0.0000 ¢
	Off-Peak (10 hr.):	(0.0076) ¢	0.0000 ¢

COMMERCIAL SERVICE -- STANDARD, Cg-2

Equivalent Monthly Customer Charge:	Single-phase	$22.00	$24.00
	Three-phase	$24.50	$27.00
Daily Customer Charge:	Single-phase	$0.7232	$0.7890
	Three-phase	$0.8054	$0.8877
Firm Demand Charges (per kW):	Summer	$7.85	$8.55
	Non-Summer	$6.70	$7.30
Customer Demand Charge		$1.70	$1.85
Energy Charge (per kWh):	Summer	4.6720 ¢	5.0080 ¢
	Non-Summer	3.7500 ¢	4.0100 ¢
Energy Limiter (per kWh):		11.2370 ¢	12.1800 ¢
Primary Voltage Discount		2.50%	2.50%
Customer Demand Discount (per kW)		$0.22	$0.22
Fuel Adjustment Clause (per kWh)		0.3805 ¢	0.0000 ¢

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	AUTHORIZED RATES

COMMERCIAL SERVICE -- Cg-2 TOD

Equivalent Monthly Customer Charge:	Single-phase	$22.00	$24.00
	Three-phase	$24.50	$27.00
Daily Customer Charge:	Single-phase	$0.7232	$0.7890
	Three-phase	$0.8054	$0.8877
Firm Demand Charges (per kW):	Summer 12 hr. On-pk	$7.85	$8.89
	Non-Summer	$6.70	$7.59
	Summer 14 hr. On-pk	$7.85	$8.55
	Non-Summer	$6.70	$7.30
Customer Demand Charge		$1.70	$1.85
Energy Charge (per kWh):			
On-Peak (12 hr.):	Summer	5.7930 ¢	6.2190 ¢
	Non-Summer	4.8420 ¢	5.2320 ¢
Off-Peak (12 hr.):	Summer	3.1380 ¢	3.2500 ¢
	Non-Summer	3.1380 ¢	3.2500 ¢
On-Peak (14 hr.):	Summer	5.5970 ¢	5.9800 ¢
	Non-Summer	4.6780 ¢	5.0310 ¢
Off-Peak (10 hr.):	Summer	3.0320 ¢	3.2500 ¢
	Non-Summer	3.0320 ¢	3.2500 ¢
Primary Voltage Discount		2.50%	2.50%
Customer Demand Discount (per kW)		$0.22	$0.22
Fuel Adjustment Clause (per kWh)	On-Peak (12 hr.):	0.8895 ¢	0.0000 ¢
	Off-Peak (12 hr.):	(0.0067) ¢	0.0000 ¢
	On-Peak (14 hr.):	0.7625 ¢	0.0000 ¢
	Off-Peak (10 hr.):	(0.0076) ¢	0.0000 ¢

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	AUTHORIZED RATES

INDUSTRIAL SERVICE, Cp-1

Equivalent Monthly Customer Charge		$213.00	$225.00
Daily Customer Charge		$7.0027	$7.4000
Firm Demand Charges (per kW):	Summer 12 hr. On-pk	$9.55	$10.76
	Non-Summer	$8.39	$9.46
	Summer 14 hr. On-pk	$9.55	$10.35
	Non-Summer	$8.39	$9.10
Customer Demand Charge		$1.70	$1.85
Interruptible Demand Charges:			
1 Hr. Notice (12 hr):	Summer	$6.01	$7.22
	Non-Summer	$4.85	$5.92
Instantaneous (12 hr):	Summer	$5.23	$6.44
	Non-Summer	$4.07	$5.14
1 Hr. Notice (14 hr):	Summer	$6.01	$6.81
	Non-Summer	$4.85	$5.56
Instantaneous (14 hr):	Summer	$5.23	$6.03
	Non-Summer	$4.07	$4.78
Energy Charge (per kWh):			
On-Peak (12 hr.):	Summer	5.0150 ¢	5.4700 ¢
	Non-Summer	4.2040 ¢	4.5980 ¢
Off-Peak (12 hr.):	Summer	2.6810 ¢	2.8100 ¢
	Non-Summer	2.6810 ¢	2.8100 ¢
On-Peak (14 hr.):	Summer	4.8450 ¢	5.2600 ¢
	Non-Summer	4.0620 ¢	4.4210 ¢
Off-Peak (10 hr.):	Summer	2.5900 ¢	2.8100 ¢
	Non-Summer	2.5900 ¢	2.8100 ¢
Energy Limiter (per kWh):		11.2370 ¢	12.1800 ¢
Reactive Energy		11.2370 ¢	12.1800 ¢
Fuel Adjustment Clause (per kWh)	On-Peak (12 hr.):	0.8895 ¢	0.0000 ¢
	Off-Peak (12 hr.):	(0.0067) ¢	0.0000 ¢
	On-Peak (14 hr.):	0.7625 ¢	0.0000 ¢
	Off-Peak (10 hr.):	(0.0076) ¢	0.0000 ¢

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	AUTHORIZED RATES

INDUSTRIAL SERVICE, Cp-2 -- Transmission

Equivalent Monthly Customer Charge		$540.00	$540.00
Daily Customer Charge		$17.7534	$17.7534
Firm Demand Charges (per kW):	Summer 12 hr. On-pk	$8.95	$10.18
	Non-Summer	$7.80	$8.95
	Summer 14 hr. On-pk	$8.95	$9.79
	Non-Summer	$7.80	$8.61
Customer Demand Charge		$0.85	$1.00
Interruptible Demand Charges:			
1 Hr. Notice (12 hr):	Summer	$5.59	$6.82
	Non-Summer	$4.44	$5.59
Instantaneous (12 hr):	Summer	$4.90	$6.13
	Non-Summer	$3.75	$4.90
1 Hr. Notice (14 hr):	Summer	$5.59	$6.43
	Non-Summer	$4.44	$5.25
Instantaneous (14 hr):	Summer	$4.90	$5.74
	Non-Summer	$3.75	$4.56
Energy Charge (per kWh):			
On-Peak (12 hr.):	Summer	4.7850 ¢	5.1750 ¢
	Non-Summer	4.0120 ¢	4.3490 ¢
Off-Peak (12 hr.):	Summer	2.5750 ¢	2.6580 ¢
	Non-Summer	2.5750 ¢	2.6580 ¢
On-Peak (14 hr.):	Summer	4.6230 ¢	4.9760 ¢
	Non-Summer	3.8760 ¢	4.1820 ¢
Off-Peak (10 hr.):	Summer	2.4710 ¢	2.6580 ¢
	Non-Summer	2.4710 ¢	2.6580 ¢
Reactive Energy		0.0946 ¢	0.0946 ¢
Load Factor Energy Credit (per kWh):		0.0000 ¢	(0.4500) ¢
Fuel Adjustment Clause (per kWh)	On-Peak (12 hr.):	0.8895 ¢	0.0000 ¢
	Off-Peak (12 hr.):	(0.0067) ¢	0.0000 ¢
	On-Peak (14 hr.):	0.7625 ¢	0.0000 ¢
	Off-Peak (10 hr.):	(0.0076) ¢	0.0000 ¢

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES		AUTHORIZED RATES	

TRAFFIC SIGNAL SERVICE, Mz-1

Equivalent Monthly Customer Charge -- 1-phase Secondary		$4.60		$4.90	
Daily Customer Charge		$0.1512		$0.1611	
Energy Charge (per kWh):	Summer	8.4650	¢	8.8700	¢
	Non-Summer	7.5470	¢	7.9500	¢
Fuel Adjustment Clause (per kWh)		0.2415	¢	0.0000	¢

CIVIL DEFENSE & FIRE SIRENS SERVICE, Mz-2

Equivalent Monthly Customer Charge:	Single-phase Secondary	$1.15		$1.18	
	Three-phase Secondary	$4.43		$4.53	
	3 phase Add'l. 10 kW	$1.16		$1.19	
Daily Customer Charge:	Single-phase Secondary	$0.0378		$0.0387	
	Three-phase Secondary	$0.1456		$0.1489	
	3 phase Add'l. 10 kW	$0.0381		$0.0390	
Fuel Adjustment Clause (per kWh)		0.0000	¢	0.0000	¢

STREET LIGHTING SERVICE, Ms-1

Annual Charges (per Unit):					
Horizontal Mast Arm		$90.80		$94.30	
Horizontal Bracket		$68.80		$71.40	
Aluminum Pole		$126.50		$131.30	
Aluminum Pole - Pole Upfront		$52.00		$54.00	
Aluminum Pole - Pole & Fixture		$33.00		$34.30	
Concrete Pole		$200.10		$207.70	
Concrete Pole - Pole Upfront		$52.00		$54.00	
Concrete Pole - Pole & Fixture		$33.00		$34.30	
Energy Charge (per kWh):	Summer	4.7800	¢	4.9200	¢
	Non-Summer	4.7800	¢	4.9200	¢
Fuel Adjustment Clause (per kWh)		0.1387	¢	0.0000	¢
Daily Credits for Continued Lamp Outage (per Fixture):					
S54-SB-100 (100 W HPS w/ 17 W ballast)		6.1290	¢	6.3080	¢
S55SC-150 (150 W HPS w/ 25 W ballast)		9.1670	¢	9.4360	¢
S50VA-250/S (250 W HPS w/ 45 W ballast)		15.4530	¢	15.9060	¢
S51WA-400 (400 W HPS w/ 80 W ballast)		25.1440	¢	25.8810	¢

ELECTRIC RATES BY RATE CLASSIFICATION	PRESENT RATES	AUTHORIZED RATES
AREA LIGHTING SERVICE, Ms-3		
Monthly Charges (per Fixture):		
100W Existing Wood Pole Roadway Overhead	$10.20	$10.50
150W Existing Wood Pole Roadway Overhead	$11.40	$11.80
250W Existing Wood Pole Roadway Overhead	$14.50	$14.90
250W Existing Wood Pole Flood Overhead	$15.70	$16.20
400W Existing Wood Pole Flood Overhead	$17.40	$17.90
100W New Wood Pole Roadway Overhead	$18.70	$19.30
150W New Wood Pole Roadway Overhead	$19.90	$20.50
250W New Wood Pole Roadway Overhead	$22.90	$23.60
250W New Wood Pole Flood Overhead	$24.20	$25.00
400W New Wood Pole Flood Overhead	$25.90	$26.70
100W New Decorative Pole Roadway Overhead	$21.10	$21.80
150W New Decorative Pole Roadway Overhead	$22.30	$23.00
250W New Decorative Pole Roadway Overhead	$24.70	$25.50
250W New Decorative Pole Flood Overhead	$26.50	$27.30
400W New Decorative Pole Flood Overhead	$28.30	$29.20
100W Existing Wood Pole Roadway Undergnd	$18.00	$18.60
150W Existing Wood Pole Roadway Undergnd	$18.70	$19.30
250W Existing Wood Pole Roadway Undergnd	$21.40	$22.10
250W Existing Wood Pole Flood Underground	$22.60	$23.30
400W Existing Wood Pole Flood Underground	$24.70	$25.50
100W New Wood Pole Roadway Underground	$26.50	$27.30
150W New Wood Pole Roadway Underground	$27.40	$28.20
250W New Wood Pole Roadway Underground	$29.90	$30.80
250W New Wood Pole Flood Underground	$31.10	$32.10
400W New Wood Pole Flood Underground	$33.40	$34.40
70W Upfront Concrete/Fiberglass Pole Acorn	$19.90	$20.50
70W New Concrete Pole Acorn	$22.00	$22.70
70W New Fiberglass Pole Acorn	$22.00	$22.70
150W Upfront Concrete/Fiberglass Pole Acorn	$22.30	$23.00
150W New Concrete Pole Acorn	$33.80	$34.80
150W New Fiberglass Pole Acorn	$31.40	$32.40

Continued on next page.

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	AUTHORIZED RATES

AREA LIGHTING SERVICE, Ms-3 (Continued)

Monthly Charges (per Fixture):			
70W Upfront Concrete/Fiberglass Pole Colonial		$17.40	$17.90
70W New Concrete Pole Colonial		$18.40	$19.00
70W New Fiberglass Pole Colonial		$18.40	$19.00
150W Upfront Concrete/Fiberglass Pole Colonial		$18.70	$19.30
150W New Concrete Pole Colonial		$29.60	$30.50
150W New Fiberglass Pole Colonial		$27.10	$27.90
250W Upfront Pole Downlight Fixture		$21.10	$21.80
250W Upfront Downlight Additional Fixture		$21.10	$21.80
250W New Pole Downlight Fixture		$35.90	$37.00
400W Upfront Pole Downlight Fixture		$22.30	$23.00
400W Upfront Downlight Additional Fixture		$22.30	$23.00
400W New Pole Downlight Fixture		$41.60	$42.90
250W Upfront Pole Metal Halide Fixture		$23.60	$24.30
250W Upfront Metal Halide Additional Fixture		$23.60	$24.30
250W New Pole Metal Halide Fixture		$38.30	$39.50
400W Upfront Pole Metal Halide Fixture		$24.70	$25.50
400W Upfront Metal Halide Additional Fixture		$24.70	$25.50
400W New Pole Metal Halide Fixture		$44.10	$45.50
Fuel Adjustment Clause (per Fixture)		13.000 ¢	0.0000 ¢

DECORATIVE LIGHTING SERVICE, Ms-2

Monthly Charges (per Fixture):			
70 W Single		$16.20	$16.60
70 W Double		$24.30	$25.00
Energy Charge (per kWh):	Summer	4.8440 ¢	4.9200 ¢
	Non-Summer	4.8440 ¢	4.9200 ¢
Fuel Adjustment Clause (per kWh)		0.1387 ¢	0.0000 ¢

NON-STANDARD LIGHTING SERVICE, NL-1

Monthly Rate (applies to $ of investment)		1.80%	1.80%
Energy Charge (per kWh):	Summer	4.8900 ¢	5.1000 ¢
	Non-Summer	4.8900 ¢	5.1000 ¢
Fuel Adjustment Clause (per kWh)		0.2045 ¢	0.0000 ¢

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	AUTHORIZED RATES

PARALLEL GENERATION, Pgs-1

Equivalent Monthly Customer Charge:	For Facilities Rated at 20-200 kW	$9.75	$9.75
	For Facilities Rated > 200 kW	$19.50	$19.50
Daily Customer Charge:	For Facilities Rated at 20-200 kW	$0.3205	$0.3205
	For Facilities Rated > 200 kW	$0.6411	$0.6411
Standard Energy Payments - based on Delivery Voltage (per kWh):			
Transmission Voltage:	On-Peak	5.380 ¢	6.000 ¢
	Off-Peak	2.190 ¢	2.453 ¢
Primary Voltage:	On-Peak	5.530 ¢	6.160 ¢
	Off-Peak	2.250 ¢	2.520 ¢
Secondary Voltage	On-Peak	5.690 ¢	5.990 ¢
	Off-Peak	2.310 ¢	2.449 ¢

TRANSFORMER RENTAL, Cp-8

AVERAGE COST of TRANSFORMERS		
Pole Mount - Single Phase		
3 kVA or Smaller	$455.21	$465.99
10 kVA	$416.43	$418.63
25 kVA	$601.20	$600.91
50 kVA	$947.92	$941.96
75 kVA	$1,515.49	$1,573.86
100 kVA	$1,901.26	$2,046.58
167 kVA	$2,371.67	$2,431.61
Pad Mount - Single Phase		
25 kVA	$962.72	$985.98
50 kVA	$1,155.00	$1,163.77
100 kVA	$1,503.67	$1,656.37
167 kVA	$2,206.46	$2,207.75

Continued on next page.

ELECTRIC RATES BY RATE CLASSIFICATION		PRESENT RATES	AUTHORIZED RATES

TRANSFORMER RENTAL, Cp-8 (continued)

AVERAGE COST of TRANSFORMERS			
Pad Mount - Three Phase			
75 kVA		$3,347.54	$3,394.68
150 kVA		$3,769.19	$3,910.95
300 kVA		$4,674.83	$4,699.75
500 kVA		$6,754.12	$6,603.56
750 kVA		$9,327.45	$9,049.11
1000 kVA		$10,306.56	$10,066.60
1500 kVA		$14,644.47	$14,051.82
2500 kVA		$20,280.65	$19,964.74
MONTHLY CHARGES for TRANSFORMERS			
Pole Mount - Single Phase			
3 kVA or Smaller	per Month	$6.83	$6.99
10 kVA	per Month	$6.25	$6.28
25 kVA	per Month	$9.02	$9.01
50 kVA	per Month	$14.22	$14.13
75 kVA	per Month	$22.73	$23.61
100 kVA	per Month	$28.52	$30.70
167 kVA	per Month	$35.57	$36.47
Pad Mount - Single Phase			
25 kVA	per Month	$14.44	$14.79
50 kVA	per Month	$17.32	$17.46
100 kVA	per Month	$22.56	$24.85
167 kVA	per Month	$33.10	$33.12
Pad Mount - Three Phase			
75 kVA	per Month	$50.21	$50.92
150 kVA	per Month	$56.54	$58.66
300 kVA	per Month	$70.12	$70.50
500 kVA	per Month	$101.31	$99.05
750 kVA	per Month	$139.91	$135.74
1000 kVA	per Month	$154.60	$151.00
1500 kVA	per Month	$219.67	$210.78
2500 kVA	per Month	$304.21	$299.47

WISCONSIN POWER AND LIGHT COMPANY
Natural Gas Revenue Summary

Authorized Distribution Class	Present Distribution Class	Present Distribution Revenues	Authorized Revenue Change $	Authorized Distribution Revenues	Authorized Revenue Change %
Gg-1 Residential	Gg-1 Residential	$ 51,019,021	$ 1,439,495	$ 52,458,516	2.82%
Gc-1 Small Commercial	Gc-1 Small Firm Commercial	7,194,745	193,511	7,388,256	2.69%
Gc-2 Commercial & Industrial	Gc-2 Medium Firm C&I <=20,000 therms/yr.	5,738,707	153,311	5,892,018	2.67%
Gc-3 Commercial & Industrial	Gc-2 Medium Firm C&I >20,000 therms/yr. Ig-1 Small Interruptible	7,332,702	14,581	7,347,283	0.20%
Gc-4 Commercial & Industrial	Gc-3 Large Firm C & I Ig-2 Medium Interruptible, Nongeneration	4,045,371	21,948	4,067,319	0.54%
Gc-5 Commercial & Industrial	Ig-3 Large Interruptible, Nongeneration	1,682,379	46,966	1,729,345	2.79%
Gc-6 Commerical & Industrial	Ig-4 SuperLarge Interruptible, Nongeneration	375,732	13,347	389,079	3.55%
GN-9 Small Generation	Ig-2 Medium Interruptible, Generation Ig-3 Large Interruptible, Generation	843,652	24,404	868,056	2.89%
GN-10 Large Generation	Ig-4 SuperLarge Interruptible, Generation	3,346,374	115,403	3,461,777	3.45%
S-1 Seasonal Service	S-1 Seasonal Service	332,548	12,309	344,857	3.70%
CS-1 Contract Rate	CS-1 Contract Rate	491,852		491,852	
Total Distribution Service Revenues		**$ 82,403,083**	**$ 2,035,275**	**$ 84,438,358**	**2.47%**
Gas Supply Revenues		$ 178,794,000		$ 178,794,000	
Total Distribution and Gas Supply Revenues		$ 261,197,083		$ 263,232,358	
Other Revenues		$ 118,000		$ 118,000	
Total Natural Gas Revenues		$ 261,315,083		$ 263,350,358	

WISCONSIN POWER AND LIGHT COMPANY

Present and Authorized Natural Gas Rates

PRESENT DISTRIBUTION CLASS	PRESENT RATES		AUTHORIZED DISTRIBUTION CLASS	AUTHORIZED RATES	
Gg-1 Residential			**Gg-1 Residential**		
Customer Charge/Day	$	0.2400	Customer Charge/Day	$	0.2400
Distribution Service Rate/Therm	$	0.2903	Distribution Service Rate/Therm	$	0.3021
Gc-1 Small Commercial			**Gc-1 Small Commercial**		
Customer Charge/Day	$	0.3902	Customer Charge/Day	$	0.3902
Distribution Service Rate/Therm	$	0.2099	Distribution Service Rate/Therm	$	0.2185
Gc-2 Medium Firm C & I <= 20,000 therms/yr.			**Gc-2 Commercial & Industrial**		
Customer Charge/Day	$	1.80	Customer Charge/Day	$	1.80
Distribution Service Rate/Therm	$	0.1124	Distribution Service Rate/Therm	$	0.1180
Gc-2 Medium Firm C & I >20,000 therms/yr.			**Gc-3 Commercial & Industrial**		
Customer Charge/Day	$	1.80	Customer Charge/Day	$	3.00
Distribution Service Rate/Therm	$	0.1124	Distribution Service Rate/Therm	$	0.1047
Ig-1 Small Interrutible			**Gc-3 Commercial & Industrial**		
Customer Charge/Day	$	5.00	Customer Charge/Day	$	3.00
Distribution Service Rate/Therm	$	0.1025	Distribution Service Rate/Therm	$	0.1047
Gc-3 Large Firm C & I			**Gc-4 Commercial & Industrial**		
Customer Charge/Day	$	21.3699	Customer Charge/Day	$	21.3699
Distribution Service Rate/Therm	$	0.0798	Distribution Service Rate/Therm	$	0.0712
Ig-2 Medium Interruptible, Nongeneration			**Gc-4 Commercial & Industrial**		
Customer Charge/Day	$	21.3699	Customer Charge/Day	$	21.3699
Distribution Service Rate/Therm	$	0.0675	Distribution Service Rate/Therm	$	0.0712
Ig-3 Large Interruptible, Nongeneration			**Gc-5 Commercial & Industrial**		
Customer Charge/Day	$	36.1598	Customer Charge/Day	$	36.1598
Distribution Service Rate/Therm	$	0.0453	Distribution Service Rate/Therm	$	0.0467
Ig-4 SuperLarge Interruptible, Nongeneration			**Gc-6 Commercial & Industrial**		
Customer Charge/Day	$	41.0998	Customer Charge/Day	$	41.0998
Distribution Service Rate/Therm	$	0.0297	Distribution Service Rate/Therm	$	0.0308
Ig-2 Medium Interruptible, Generation			**GN-9 Small Generation**		
Customer Charge/Day	$	21.3699	Customer Charge/Day	$	36.1598
Distribution Service Rate/Therm	$	0.0675	Distribution Service Rate/Therm	$	0.0492
Ig-3 Large Interruptible, Generation			**GN-9 Small Generation**		
Customer Charge/Day	$	36.1598	Customer Charge/Day	$	36.1598
Distribution Service Rate/Therm	$	0.0453	Distribution Service Rate/Therm	$	0.0492

WISCONSIN POWER AND LIGHT COMPANY

Present and Authorized Natural Gas Rates

PRESENT DISTRIBUTION CLASS	PRESENT RATES		AUTHORIZED DISTRIBUTION CLASS	AUTHORIZED RATES	
Ig-4 SuperLarge Interruptible, Generation			**GN-10 Large Generation**		
Customer Charge/Day	$	41.0998	Customer Charge/Day	$	50.00
Distribution Service Rate/Therm	$	0.0297	Distribution Service Rate/Therm	$	0.0307
S-1 Seasonal			**S-1 Seasonal**		
Customer Charge/Day	$	1.03	Customer Charge/Day	$	1.22
On-Season Distribution Service Rate/Th.	$	0.1433	On-Season Distribution Service Rate/Th.	$	0.1433
Block 1 Off-Season Distrib. Serv. Rate/Th.	$	0.1433	Block 1 Off-Season Distrib. Serv. Rate/Th.	$	0.1433
Block 2 Off-Season Distrib. Serv. Rate/Th.	$	0.1078	Block 2 Off-Season Distrib. Serv. Rate/Th.	$	0.1078
Block 3 Off-Season Distrib. Serv. Rate/Th.	$	0.0923	Block 3 Off-Season Distrib. Serv. Rate/Th.	$	0.0923

Authorized Gas Supply Acquisition Rates:

Residential Gas Supply Acquistion Rate/Therm	$0.0191
Nonresidential Firm Gas Supply Acquisition Rate/Therm	$0.0189
Nonresidential Interruptible Gas Supply Acquisition Rate/Therm	$0.0176

Authorized Gas Supply Base Rates:

Base Commodity Rate/Therm	$0.7072
Base Maximum Daily Delivery Rate/Therm	$0.0922
Base Annual Demand Rate/Therm	$0.0413

Lost and Unaccounted for Gas Factor

Lost and Unaccounted for Gas Factor	0.85

Wisconsin Power and Light Company
6680-UR-114
Monthly Fuel Monitoring Costs for the 12 Months Ended June 30, 2006

Line #	Month	Net MWh Produced		Fuel Costs		Fuel Costs per Net kWh Produced		Cummulative Cost per kWh
1	July-05	1,492,911	$	38,815,740	$	0.02600	$	0.03874
2	August-05	1,470,903	$	37,251,353	$	0.02533	$	0.03814
3	September-05	1,231,737	$	24,263,135	$	0.01970	$	0.03191
4	October-05	1,219,034	$	22,638,821	$	0.01857	$	0.03156
5	November-05	1,146,309	$	20,534,676	$	0.01791	$	0.02965
6	December-05	1,268,620	$	26,115,389	$	0.02059	$	0.03279
7	January-06	1,333,731	$	31,710,925	$	0.02378	$	0.03445
8	February-06	1,215,298	$	33,349,809	$	0.02744	$	0.03136
9	March-06	1,273,534	$	32,672,929	$	0.02566	$	0.03284
10	April-06	1,182,749	$	30,488,656	$	0.02578	$	0.03048
11	May-06	1,202,736	$	29,337,516	$	0.02439	$	0.03097
12	June-06	1,295,657	$	27,901,815	$	0.02153	$	0.03333
13	Total	15,333,219	$	355,080,765	$	0.02316	$	0.02316